**STATE OF ILLINOIS**

**ILLINOIS COMMERCE COMMISSION**

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| **ILLINOIS POWER COMPANY** | **)** | |
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| **Proposed revisions to delivery services** | **)** | **01-0432** |
| **Tariff sheets and other sheets.** | **)** | |

# ILLINOIS POWER COMPANY'S INITIAL BRIEF


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## TABLE OF CONTENTS

**Page**

**TABLE OF CONTENTS**
(continued)

**Page**

**TABLE OF CONTENTS**
(continued)

**Page**

**TABLE OF CONTENTS**
(continued)

**Page**

# I. INTRODUCTION

On June 1, 2001, Illinois Power Company ("Illinois Power", "IP" or "Company") filed with the Commission tariff sheets by which IP proposed (1) to increase its rates for delivery services offered to non-residential customers, (2) to establish rates for the provision of delivery services to residential customers, commencing May 1, 2002, and (3) to implement various revisions and additions to the terms and conditions on which the Company provides delivery services under Service Classifications ("SC") 110 and 150 and various applicable riders. The Commission suspended the proposed tariffs until October 28, 2001, and later resuspended the proposed tariffs to April 28, 2002.

Illinois Power's initial filing proposed a revenue requirement for electric distribution service of $311,716,000, based on a 2000 test year with adjustments. (IP Exs. 3.8-3.9) The proposed distribution revenue requirement reflected a 9.22% rate of return on rate base, including a 12.50% rate of return on common equity. (IP Ex. 3.2) As a result of various revisions to the original filing occurring throughout the case, and IP's agreement with various ratemaking adjustments proposed by other parties, the Company's final proposed electric distribution revenue requirement is $295,950,000.[1] (Rev. IP Ex. 3.25) The components of Illinois Power's proposed distribution rate base are addressed in Section II.B of this brief, while the proposed distribution operating income statement is addressed in Section II.C. As described in Section II.D below, the proposed revenue requirement reflects a rate of return on rate base of 8.69% including an 11.89% rate of return on common equity. (Staff Ex. 20.0) The rate of return on rate base

[1] This is the "gross" revenue requirement and does not reflect miscellaneous revenues such as service initiation fees and reconnection fees. Test year miscellaneous revenues are deducted from the "gross" revenue requirement to arrive at a "net" revenue requirement that is then used to set rates and charges.

and the component capital structure balances and cost rates (including the 11.89% rate of return on common equity) were agreed to among the three parties (IP, Commission Staff and the Illinois Industrial Energy Consumers ("IIEC")) presenting rate of return evidence); so far as IP is aware, no other party has objected to the agreed rate of return.

Illinois Power proposes to allocate the approved distribution revenue requirement to the customer classes based on class cost of service responsibility as determined by the revised embedded cost of service study ("ECOSS") presented by the Company in its rebuttal testimony in this case, as described in Section III.A and B of this brief. The development of IP's proposed rates and charges is described in Section III.C.

The delivery services tariffs ("DSTs") filed by the Company, in particular SC 110 and SC 150, along with the Company's Electric Standard Terms and Conditions and relevant provisions of its Rules, Regulations and Conditions Applying to Electric Service, have been substantially revised and reorganized with the objective of streamlining and simplification.[2] In addition, SC 110 and SC 150 have been reorganized in accordance with the outline for DSTs approved by the Commission in Docket 00-0494. The delivery services tariffs and applicable riders have also been modified as necessary to provide for the offering of delivery services to residential customers, commencing May 1, 2002. Specific changes in the terms and conditions of delivery services and in applicable riders, including Rider PPO – Power Purchase Option Service and Rider ISS – Interim Supply Service, are described in Section IV of this brief.

[2] SC 110 is "Delivery Services". SC 150 is "Service for Customer Self-Managers, Retail Electric Suppliers and Meter Service Providers".

## II. REVENUE REQUIREMENTS

### A. Test Year

Illinois Power proposed an historical test year consisting of the twelve months ended December 31, 2000, with adjustments for known and measurable changes and other pro forma adjustments. No party opposed the use of an historical 2000 test year.

### B. Distribution Rate Base

#### 1. Overview of IP's Proposed Distribution Rate Base

Illinois Power proposes the following distribution rate base (Rev. IP Ex. 3.24)[3]:

| Item | Amount (000) |
|---|---|
| Plant in Service | |
| Distribution Plant | $1,472,356.0 |
| General Plant | 201,730.0 |
| Intangible Plant | 70,714.0 |
| Accum. Depreciation – Distribution | ( 577,623.0) |
| Accum. Depreciation – General | ( 37,210.0) |
| Accum. Depreciation – Intangible | ( 54,664.0) |
| Net Plant in Service | $1,075,303.0 |
| Adjustments to Rate Base | |
| Land Held for Future Use | --- |
| CWIP – Not including AFUDC | 5,592.0 |
| Dep. Res. – Contrib. Elec. Distrib. | 2,870.0 |
| Working Capital | 9,960.0 |
| Reserve for Deferred Income Taxes | ( 180,948.0) |
| Customer Deposit Balance | ( 2,044.0) |
| Customer Advances for Construction | ( 1,032.0) |
| Pre-1971 Investment Tax Credits | ( 538.0) |
| Total Adjustments to Rate Base | ( 166,140.0) |
| Total Rate Base | $ 909,163.0 |

[3] Rev. IP Ex. 3.24 shows the December 31, 2000 balances for rate base and expense items and shows the components of each ratemaking adjustment, both uncontested and contested, to arrive at IP's proposed rate base and operating expenses.

### 2. **Uncontested Adjustments to Rate Base**

Illinois Power's proposed rate base incorporates a number of adjustments that were proposed by the Company and not opposed by any other party, as well as a number of adjustments that were proposed by other parties and accepted by the Company. The following paragraphs summarize these uncontested adjustments.

**Load research project.** The rate base includes capital investment that has been incurred for acquisition and installation of specialized load research meters to collect data, and other infrastructure costs, for a load research program. The data collected will be used to develop load profiles specific to the IP service area and for other distribution planning purposes. This adjustment increases rate base by $1,554,000. (IP Ex. 6.1, p. 28; IP Ex.6.5; IP Exs. 1.65, 1.67, 1.75; Rev. IP Ex. 3.24, p. 1, col. (5))

**FAS 109 Gross-up.** In order to keep the rate base neutral with respect to FAS-109-related deferred income taxes, IP removed FAS-109-related gross-ups for net-of-tax AFUDC in utility plant in service from the balances in Accounts 101 and 106. This adjustment reduces rate base by $1,424,000. (IP Ex. 1.1, pp. 10-11; IP Exs. 1.6, 1.65; Rev. IP Ex. 3.24, p. 1, col. (6))

**CWIP transferred to Utility Plant in Service.** At December 31, 2000, the Company's Construction Work in Progress ("CWIP") accounts included dollars for projects which had already been completed and placed in service, but not yet transferred from the CWIP accounts to the applicable plant in service account. This adjustment recognizes these amounts as plant in service. The adjustment increases rate base by $7,840,000. (IP Ex. 1.1, p. 11; Corrected Rev. IP Ex. 1.6; IP Exs. 1.65, 1.67, 1.75; Rev. IP Ex. 3.24, p. 1, col. (7))

**Facilities no longer in use.** The Company has closed or is closing a number of facilities that were included in plant in service accounts as of December 31, 2000. These facilities include a total of 12 service area buildings and other buildings in various cities throughout IP's service area. This adjustment removes the investment in these facilities, and the related accumulated depreciation and deferred tax reserve, from rate base. The adjustment reduces rate base by $157,000. (IP Ex. 1.1, pp. 11-12; IP Ex. 2.1, p. 19; IP Exs. 1.8, 1.29, 1.65, 1.67, 1.75; Rev. IP Ex. 3.24, p. 1, col. (8))

**Unamortized pre-1971 Investment Tax Credits ("ITC").** This adjustment reduces the amount of unamortized pre-1971 ITC and thus increases rate base. This adjustment, which recognizes additional amortization of pre-1971 ITC from January 1, 2001 through September 30, 2001, was implemented in connection with recognizing additional accumulated depreciation for the same period on plant in service at December 31, 2001, as proposed by David Effron, who testified on behalf of the Citizens Utility Board ("CUB") and the Attorney General ("AG"). This adjustment increases rate base by $26,000. (Rev. IP Ex. 3.24, p. 3, col. (26))

**Cash working capital.** IP's proposed rate base includes an allowance for cash working capital.[4] The Company developed the cash working capital component by performing a lead/lag study, using a methodology similar to the one presented and adopted in IP's 1999 DST case, Dockets 99-0120 & 99-0134 (Cons.) ("1999 DST Case"). (IP Ex. 1.1, pp. 12-13) During the course of the case, IP made revisions to the cash working capital study to take into account revisions and adjustments to various revenue,

[4] The "Working Capital" component of rate base shown in the table in Section II.B.1 above consists of (1) a 13-month average balance of materials and supplies, less the average balance of the related accounts payable (IP Ex. 1.1, p. 6) plus (2) the cash working capital allowance.

expense and return items that are components of the study. In addition, CUB/AG witness Effron proposed two substantive adjustments to IP's cash working capital study; IP accepted both of these adjustments, although it implemented one of them somewhat differently than Mr. Effron had proposed. (GCI Ex. 2.0, pp. 25-27; IP Ex. 1.34, pp. 22-25) Mr. Effron accepted IP's implementation of his adjustment. (GCI Ex. 4.0, p. 5; Tr. 402-03) As adjusted for the Effron adjustment and other revisions, the cash working capital component included in rate base is $3,087,000. (Rev. IP Ex. 3.24, p. 1, col. (9))

### 3. Contested Adjustments to Rate Base

#### a. Post-Test Year Capital Additions

In summary, Staff and the Company agree as to the amount of post-test year capital additions to distribution plant and general and intangible ("G&I") plant that should be included in rate base.[5] CUB/AG witness Effron, in contrast, has proposed to limit post-test year capital additions to projects actually placed in service by June 30, 2001. The projects and amounts that IP and Staff have agreed should be included in rate base satisfy the "known and measurable" criteria; accordingly, the adjustment amount agreed to by IP and Staff should be accepted. Mr. Effron's adjustment is arbitrary, is not based on application of the "known and measurable" criteria or on any specific objections to any projects that have been or will be placed in service after June 30, 2001, and should be rejected.

Illinois Power proposes adjustments to the December 31, 2000 balances of plant in service, accumulated provision for depreciation and reserve for deferred taxes to

[5] While Staff agrees with IP as to the specific G&I plant additions to be included in rate base, Staff's overall rate base component for G&I plant is based on the adjustment developed by Staff witness Lazare, discussed in Section II.B.3.c below.

reflect capital additions that will be placed in service subsequent to December 31, 2000. The projects included in the proposed adjustment consist of (1) additions to distribution plant, (2) additions to G&I plant that are being placed in service exclusively or predominantly for use by the Company's Energy Delivery business group, and (3) additions to G&I plant that support corporate overhead functions.[6] The individual distribution plant additions with costs in excess of $500,000, and the G&I plant additions to be used by the Energy Delivery business group, were described and justified by IP witness John Barud. (See IP Exs. 2.8 and 2.15 and Corrected Rev. IP Ex. 2.10) The corporate G&I capital additions projects (item (3) above) were described and justified by IP witness Peggy Carter.[7] (See Corrected Rev. IP Ex. 1.5) All of the capital additions supported by these witnesses have planned in-service dates on or before June 2002; by the close of the record in this case, many of the projects had in fact been completed. (See, e.g., IP Exs. 2.8 and 2.19 and AG Cross Ex. 1)

Staff witness Mary Everson conducted an extensive review of IP's proposed capital additions, with a principal focus on whether and to what extent the capital additions projects met the "known and measurable" standard. In conducting her review,

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[6] All of the additions to G&I plant, including those being placed in service exclusively or primarily for use by the Energy Delivery business group, have been allocated between the gas and electric utilities, and the electric portion then allocated to the electric distribution function, on the same basis, resulting in 57.9% of the total cost of each of the G&I plant additions being allocated to electric distribution. (See IP Exs. 1.64, 2.19 and 2.20)

[7] As part of its adjustment for capital additions, the Company also removed from the balances of plant in service and accumulated depreciation the net cost of facilities that have been or will be retired subsequent to December 31, 2000, as a result of placement of the capital additions into service. In addition, IP provided for depreciation and deferred taxes in respect of the capital additions in the accumulated depreciation reserve and reserve for deferred taxes, respectively, through September 30, 2001. (See IP Ex. 1.1, p. 12, Corrected IP Ex. 1.31, pp. 3-5, and IP Exs. 1.64, 1.65, 1.67, 2.18, 2.19 and 2.20)

Ms. Everson referenced 83 Ill. Adm. Code 285.150(e), which sets forth the "known and measurable" criteria that apply in a general rate increase case, and section DST.160 of the minimum information requirements that were established in Docket 98-0454 for use in the initial round of DST cases. (Staff Ex. 2.0, p. 3) Although she recognized that these provisions are not officially applicable in this case, Ms. Everson testified that the "known and measurable" criteria outlined in these provisions are still valid for evaluating evidence of pro forma adjustments. (Id., p. 4) As she explained:

> Standard auditing techniques rely on the availability of certain documents and/or testing of processes to constitute evidence of reasonable certainty of amounts. Staff routinely uses the principle underlying the criteria called "known and measurable", even when it is not specifically outlined or agreed to in a proceeding, because it provides a standard by which to evaluate pro forma adjustments that is reasonable and can be applied in a variety of situations with a variety of issues and companies. (Id.)

Ms. Everson's review of IP's proposed capital additions involved review of workpapers and data request responses as well as information in the Company's filed testimony. Ms. Everson testified that IP supplied her with copies of procedures and other internal documents that described the processes by which plant additions are identified, designed, cost estimated, approved by management, and funded by management. She stated that IP provided her with information that enabled her to determine which of its proposed plant additions projects had received funding approval from management and which had not. The Company also provided Ms. Everson with information that showed the actual expenditures that had been made and the remaining expenditures on those projects that had received funding approval. In addition, Ms. Everson stated that IP provided her with access to work orders, work requests, invoices and similar documents that supported the actual and planned expenditures for the capital additions projects. (Tr. 119-121) As she stated in her direct testimony:

> In evaluating IP's pro forma plant additions, I considered the substance of the known and measurable criteria, as I believe it relates to the pro forma adjustments presented by the Company. IP presented evidence of the processes that comprise the development of capital projects, from identification, initial and final design, costing and funding approval for plant additions. After obtaining supporting documents and review of the processes, I determined that the key element of the known and measurable criteria to apply in this instance is the funding approval by management. The funding approval is the element of the known and measurable criteria that provides evidence of reasonable certainty for amounts in addition to actual amounts expended by the Company. The projects for which the Company has provided evidence of a funding approval, are, in my estimation, both known and capable of being measured with reasonable certainty. (Staff Ex. 2.0, p. 5)

On this basis, Ms. Everson identified those projects and amounts in IP's proposed adjustments for capital additions that were "known and measurable" and should be included in rate base, and those that were not "known and measurable" and thus should be excluded from rate base. (Id., p. 6)

Illinois Power accepted Ms. Everson's limitation on allowable capital additions to actual and remaining expenditures on those projects that have received funding approval from management. (IP Ex. 2.13, pp. 1-2) In accordance with the approach adopted by Ms. Everson, IP presented information on its actual expenditures as of September 30, 2001, and remaining expenditures, on projects that had received funding approval as of September 30. (IP Exs. 1.64, 2.18, 2.19, 2.20) Ms. Everson reviewed this information (including supporting information provided through data requests) and concluded that the capital additions amounts proposed by IP for inclusion in rate base are "known and measurable." (Tr. 122-124) The resulting capital additions to distribution rate base, net of related retirements, as shown on IP Exhibits 1.64 and 2.18-2.20, are as follows:

| | |
|---|---|
| Distribution plant additions: | $80,195,901 |
| General plant additions for Energy Delivery: | $ 1,976,455 |
| Intangible plant additions for Energy Delivery: | $ 1,303,082 |
| Corporate G&I plant additions: | $10,789,000 |

Although Staff and the Company agreed on the basis for and amount of capital additions to be included in rate base, CUB/AG witness Effron proposed that capital additions be limited to the investment in projects that had actually been placed in service as of June 30, 2001. The reasons Mr. Effron gave for this limitation (in addition to a general aversion to allowing any post-test year additions, which he recognized would be inconsistent with past practices of this Commission, see GCI Ex. 2.0, p. 21) were: (1) IP was not recognizing additional accumulated depreciation subsequent to December 31, 2000, on plant in service as of that date; (2) IP was not recognizing growth in billing determinants beyond the test year; and (3) projections of expenditures through June 30, 2002, are speculative and do not represent actual expenditures. (Id., p. 22) The reasons advanced by Mr. Effron do not support his arbitrary limitation on capital additions, and his position should be rejected.

As described later in this brief, in response to Mr. Effron's concerns, Illinois Power has increased the accumulated provision for depreciation and the reserve for deferred income taxes for the additional depreciation and deferred taxes from January 1, 2001 through September 30, 2001, relating to plant in service as of December 31, 2001. (See Section II.B.3.b below) IP also adopted Mr. Effron's proposal to use an average of the actual year-end 2000 values and the forecasted year-end 2001 values (numbers of customers and kWh) for the billing determinants, rather than using the actual billing determinants for the 12 months ended December 31, 2000, as the Company had originally proposed. In fact, IP expanded upon Mr. Effron's proposal; he only proposed using the average of the 2000 and 2001 year-end values for residential billing determinants, but the Company expanded his proposal to incorporate all customer classes.[8] (IP Ex. 6.6, pp. 3-4; Tr. 403-04) Therefore, Mr. Effron's first two concerns should no longer support his limitation on capital additions (if they ever did).

Mr. Effron's third concern, that the Company's proposed capital additions amounts included speculative projections of future expenditures, is belied by Ms. Everson's careful review of the Company's capital additions projects, and her conclusion (which IP accepted) that those projects that have gone through IP's internal processes and procedures to the point of receiving funding approval from management meet the "known and measurable" criteria. In contrast, there is no evidence that Mr. Effron conducted any actual review of the specific capital additions projects that IP proposed for inclusion in rate base.

Moreover, although the final capital additions amount proposed by IP and accepted by Ms. Everson includes remaining expenditures as of September 30, 2001 on funded projects, it also includes substantial actual expenditures as of September 30, 2001. For example, the distribution plant capital additions amount of $92,738,667 (before reduction for related retirements), consists of $77,616,116 of actual expenditures as of

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[8] Although IP accepted Mr. Effron's approach to increasing billing determinants, it should be noted that his argument that plant additions must be constructed to serve new customers does not take into account the fact that some plant additions are needed simply to replace existing plant that needs to be retired. As described above, IP has also adjusted rate base for plant retirements associated with the capital additions. Obviously, however, the cost of distribution plant being placed in service today to replace existing facilities will, in most cases, be significantly higher than the original cost of the facilities being replaced, which may have been installed many years ago.

September 30 and only $15,122,551 of remaining expenditures as of that date. (IP Ex. 2.18, p. 3) Similarly, the amount of general plant additions for Energy Delivery, $2,046,455 (before adjustment for retirements), consists of $1,982,099 of actual expenditures as of September 30 and $64,356 of remaining expenditures as of that date; and the amount of intangible plant additions for Energy Delivery, $1,303,082, consists of $713,744 of actual expenditures as of September 30 and $589,338 of remaining expenditures as of that date. (IP Exs. 2.19-2.20) In the aggregate, 83.6% of the foregoing capital additions were amounts actually expended as of September 30, 2001. (IP Ex. 2.17, p. 3)

Mr. Effron's proposed limitation of capital additions that can be included in rate base is based on an arbitrary cut-off date, is not based on any specific analysis of the capital additions projects that IP proposes for inclusion in distribution rate base, and does not reflect any meaningful analysis under the "known and measurable" criteria. None of the concerns he expressed support his limitation. His position should be rejected, and the capital additions amounts proposed by the Company, based on the "funding approval" criteria adopted by Staff witness Ms. Everson, should be accepted. The adjustment amounts are shown on Rev. IP Ex. 3.24, p. 1, col. (3) and (4).

#### b. Accumulated Depreciation on Plant in Service at December 31, 2000

In connection with the inclusion in rate base of capital additions for projects that had received funding approval from management as of September 30, 2001, Illinois Power also decreased rate base by the amount of accumulated depreciation and deferred income taxes accruing from January 1, 2001 through September 30, 2001 on plant that was in service as of December 31, 2000. (IP Ex. 1.63, pp. 20-21) This adjustment decreases rate base by $31,899,000 for additional accumulated depreciation, and by $3,448,000 for additions to the reserve for deferred taxes, subsequent to December 31, 2000. (Rev. IP Ex. 3.24, pp. 2-3, cols. (24)–(25)) The need to recognize post-year accumulated depreciation on plant in service at December 31, 2000 was originally identified by CUB/AG witness Effron. (GCI Ex. 2.0, p. 24) IP went beyond Mr. Effron's proposal by also recognizing post-December 31, 2000 growth in the provision for deferred income taxes associated with plant in service at that date.

The Company's recognition of accumulated depreciation and deferred taxes on plant in service as of December 31, 2000, through September 30, 2001, is consistent with its proposal (accepted by Staff) to include capital additions for projects that have received funding approval as of September 30, 2001. While these capital additions projects include some expenditures that will be made after September 30, 2001 on projects that will not be completed by that date, Illinois Power is <u>not</u> proposing (and Staff has not accepted) inclusion in rate base of <u>all</u> projected capital additions through June 2002. Rather, as explained in Section II.B.3.a above, IP's capital additions amount consists only of actual expenditures as of September 30, 2001, and remaining expenditures, on projects that had received funding approval as of that date.[9] Further, as discussed in Section II.B.3.a above, the Company's capital additions amount consists predominantly of <u>actual expenditures</u> as of September 30, 2001. Accordingly, IP's recognition of additional accumulated depreciation and deferred taxes, through September 30, 2001, on plant in

[9] If the Company were to include in rate base <u>all</u> of its capital additions projected through June 2002, the amount of the adjustment to rate base would be considerably larger than what IP has proposed. (IP Ex. 2.17, p. 3)

service as of December 31, 2000, is reasonable and consistent with the capital additions adjustment, and should be accepted.

### c. General and Intangible Plant included in Distribution Rate Base

#### i. IP's Determination of the Amount of G&I Plant in Distribution Rate Base using the Labor Expense Allocator

One of the steps necessary in developing the distribution rate base is to determine the amount of the utility's G&I plant that should be included in the distribution rate base. General plant consists of assets such as office buildings, furniture, computers, vehicles and other equipment. Intangible plant includes assets such as software programs. (IP Ex. 1.34, p. 4) Under the Uniform System of Accounts ("USOA"), General plant is recorded in Accounts 389–399, and Intangible plant is recorded in Accounts 301-303. (Tr. 747-48; see IP Ex. 1.39) In general, G&I plant supports all of a utility's business functions (IP Ex. 1.34, pp. 4-5), although there are some assets that the USOA requires to be recorded in the General and Intangible plant accounts which can be associated with specific lines of business or functions.[10] It is in the nature of these joint and common costs that they are needed to support a single line of business, but can also support additional lines of business without any significant increase. (Id.) The USOA does not

[10] Examples of assets recorded in General plant accounts which could be specifically identified with a specific line of business, or a subset of lines of business, include structures and equipment (e.g., office or service buildings that may be used for the purposes of a single line of business), recorded in Account 390; transportation equipment (e.g., automobiles, bucket trucks and other trucks, repair vehicles, tractors and trailers), recorded in Account 392; tools, shops and garage equipment, recorded in Account 394; and power-operated equipment (e.g., back-filling machines, boring machines, bulldozers, cranes and hoists, diggers and trenchers). See Accounts 389-399 of the Uniform System of Accounts for Electric Utilities (adopted by the Commission at 83 Ill. Adm. Code 415); IP Ex. 1.34, p. 13)

require that a utility maintain its books of account or financial reports in a manner that allocates or assigns its G&I plant investment among the utility's various business functions. (IP Ex. 1.63, p. 6; Tr. 755-57) Therefore, for regulatory purposes in setting rates for one of a utility's several lines of business, it is necessary in some manner to allocate or assign a portion of the G&I plant investment to the service for which rates are being set.

In the 1999 DST Case, Illinois Power presented a detailed "asset separation" study to determine the amount of G&I plant that should be included in distribution rate base. (IP Ex. 1.34, p.6; see 1999 DST Order, pp. 12-14) However, the Commission did not adopt IP's study for this purpose, citing as reasons (1) that costs associated with general plant may not be amenable to direct assignment to a particular function, and (2) that there was insufficient time in the 1999 DST Case to review IP's voluminous asset separation study. (1999 DST Order, p. 16; Tr. 748-49) Instead, the Commission determined the amount of G&I plant investment that should be included in distribution rate base by applying the ratio of test year distribution labor expense to total labor expense to the total Company G&I plant investment. (Tr. 748; see 1999 DST Order, pp. 15-16) This ratio is referred to as the "labor allocator".

In this case, Illinois Power, although continuing to believe that a detailed asset separation study provides the most appropriate basis for determining the amount of G&I plant to be included in distribution rate base (IP Ex. 1.34, p. 6), determined the amount of G&I plant investment that should be included in rate base by using labor expense allocation factors. (IP Ex. 1.1, pp. 5-6; IP Ex. 1.4; IP Ex. 1.34, p. 6; Tr. 749-50) IP first allocated its total G&I plant investment between the electric and gas utilities, then allocated the electric utility portion of G&I plant to electric distribution based on test year distribution labor expense divided by total test year labor expense for IP's electric transmission and electric distributions functions. (IP Ex. 1.1, pp. 5-6; IP Ex. 1.4; Tr. 750) No party noted any errors in IP's calculation of the labor allocation factors. (IP Ex. 1.34, pp. 7, 56; IP Ex. 1.63, pp. 7-8)

**ii. Staff Witness Lazare's and IIEC Witness Phillips' Adjustments Are Without Merit**

Staff witness Peter Lazare and IIEC witness Nicholas Phillips, Jr., each took issue with the amount of G&I plant that IP included in distribution rate base using the above-described labor allocation procedure. They both contended that IP's use of the labor allocator produced a large increase in the amount of G&I plant included in distribution rate base as compared to the amount of G&I plant included in distribution rate base in the order in the 1999 DST Case. At the root of each witness' contention is the fact that in the fourth quarter of 1999, IP sold its fossil generations stations to Dynegy Midwest Generation, Inc. ("DMG") and sold its nuclear generating station (Clinton) to AmerGen.[11] IP's fossil generation employees and nuclear generation employees became employees of DMG and AmerGen, respectively. As a result, whereas during the 1997 test year used in the 1999 DST Case the Company owned generating stations, had a generation business function and had generation employees whose labor expense was included in the denominator of the labor expense allocation factor, in the 2000 test year used in this case, IP owned essentially no generation, had essentially no generation labor

[11] At the time of the transfer of the fossil generating stations, the transferee company was named Illinova Power Marketing, Inc. Subsequent to the closing of the Illinova-Dynegy merger, the transferee company was renamed DMG. For convenience, the transferee is referred to in this brief as DMG.

expense, and therefore did not include any generation labor expense in the development of its labor expense allocation ratios for G&I plant. (Staff Ex. 5.0, pp. 5-6; IIEC Ex. 3, pp. 8-9; see IP Ex. 1.34, pp. 5-6)

In lieu of the amount of G&I plant to be included in distribution rate base as determined by the Company using the labor expense allocator, Mr. Lazare proposed that IP be allowed an amount of G&I plant in distribution rate base equal to the amount of G&I plant allowed in rate base in the 1999 DST Case, plus a percentage increase equal to the percent increase in distribution plant allowed in rate base in this case over the amount of distribution plant included in rate base in the 1999 DST case. (Staff Ex. 5.0, pp. 15-16, 17-18) Mr. Phillips proposed that the initial amount of net G&I plant only be increased in proportion to the increased amount of O&M expense required for delivery services.[12] (IIEC Ex. 3, p. 8)

Illinois Power properly determined the amount of its G&I plant investment that should be included in distribution rate base using a labor expense allocator as prescribed by the Commission in the 1999 DST Case. Mr. Lazare's and Mr. Phillips' proposed adjustments were not based on any sort of detailed review of IP's overall G&I plant assets or on identification of any G&I assets or amounts that were imprudently incurred or are unnecessary to provide service. Rather, their adjustments are grounded in an erroneous premise that the Commission, in the 1999 DST Case, determined a fixed and immutable relationship between the amount of distribution plant and the amount of G&I

[12] Mr. Phillips also proposed that "[t]he additions and adjustments to net Intangible and General Plant requested by IP should be allowed to the extent that IP presents valid reasons for their inclusion". (IIEC Ex. 3, p. 9) In contrast, Mr. Lazare, as discussed below, applied his limitation to IP's entire proposed balance of G&I plant, including G&I plant additions that were placed in service after IP had sold its generating assets. (Staff Ex. 14.0, pp. 11-12)

plant needed to provide distribution service, which should be carried forward in all future cases. (IP Ex. 1.63, pp. 8-9) There is no basis for such a premise, or for the arbitrary limitations Messrs. Lazare and Phillips would impose on the amount of IP's G&I assets to be included in distribution rate base.

The essence of Mr. Lazare's objection appears to be a belief that the amount of G&I plant allocated to the generation function in the 1999 DST Case must be permanently allocated to generation, and that IP should have somehow disposed of that G&I plant when it sold its generating stations to DMG and AmerGen.[13] He testified that IP had "failed to explain" how the "generation component" of G&I plant was "removed from the regulated utility" or how it had "remov[ed] the generation component from these accounts." (Staff Ex. 5.0, pp. 6-7) As he explained in response to a data request:

> 74. Explain how Mr. Lazare believes Illinois Power should have used a labor allocator to allocate G&I plant and A&G plant to "generation" in this case in light of the fact that IP had no "generation" labor in the year 2000.
>
> Response: Mr. Lazare believes that when IP divested its generation, it should have reduced G&I Plant and A&G expense accounts that provide the foundation for delivery services ratemaking in a manner consistent with the Commission's Order in Docket No. 99-0134.[14] (IP Ex. 1.34, p. 16)

As IP witness Peggy Carter, the Company's Vice President and Controller, explained, IP in fact transferred substantial G&I plant to DMG and AmerGen in

[13] Because the discussion of this issue in Mr. Lazare's direct and rebuttal testimonies was much more extensive than the discussion in Mr. Phillips' testimonies, IP's analysis of their objections and proposals will focus on Mr. Lazare's testimony.

[14] Despite Mr. Lazare's assertion that IP should have removed the "generation component" of costs from the G&I plant account, he acknowledged that the USOA requires G&I plant to be recorded and reported on a total company basis and does not provide for segregation of costs within the G&I accounts on the basis of lines of business. (Tr. 755-57)

connection with the sale of the generating stations. IP's October 1999 sale of its fossil generating stations to DMG was approved by the Commission in Docket 99-0209, a case initiated by a filing by IP under §16-111(g) of the Public Utilities Act ("PUA"). IP's filing contained a detailed listing of G&I plant being transferred to DMG as part of that transaction. G&I plant transferred to DMG included buildings, office furniture and equipment, personal computers, computer software, vehicles, stores equipment, tools, shop and garage equipment, laboratory equipment, power-operated equipment and communications equipment. The G&I plant transferred had an original cost of approximately $12.0 million and a depreciated original cost of approximately $8.3 million. (IP Ex. 1.34, p. 11; IP Ex. 1.62) Similarly, the December 1999 sale of Clinton to AmerGen included G&I assets such as mobile and non-mobile machinery, computer hardware and software, communications equipment, vehicles, tools, spare parts, fixtures, furniture and furnishings, and other personal property. The G&I assets that were sold to AmerGen had a book value of approximately $43 million before IP recognized an impairment loss for Clinton that resulted in the entire plant value being written down to zero.[15] (IP Ex. 1.34, pp. 12, 14) In total, G&I plant that had had a book value of approximately $55 million was sold to the new owners of IP's generating stations.[16] (Id., p. 14)

[15] IP recognized the impairment loss for Clinton in December 1998. (IP Ex. 1.34, p. 14)

[16] As Ms. Carter testified, at the time of the sales to DMG and AmerGen, there were no concerns or complaints raised by Commission Staff or anyone else that IP was not transferring enough G&I plant to the new owners of the generating facilities. (IP Ex. 1.34, p. 16) In this case, Mr. Lazare did not identify any additional G&I plant items that he contended should have been transferred to DMG or AmerGen. (Id., p. 17)

In addition, subsequent to the sale of its fossil and nuclear generation, IP has continued to take other actions to reduce the level of its G&I plant, by consolidating facilities and eliminating unneeded assets. For example, IP is selling a building that had been intended for use as offices for the Company's fossil generation management personnel.[17] As another example, IP has closed and sold a facility that was once used to house historical records. The records are now stored in space that became available in IP's headquarters building. (IP Ex. 1.34, p. 15)

However, other G&I plant that, had IP continued to own generating facilities, might have been allocated among generation, distribution and other functions for ratemaking purposes, was not sold or transferred to DMG or AmerGen, or otherwise disposed of, for two reasons. First, the remaining G&I assets are needed to support the Company's remaining lines of business, including electric distribution. (IP Ex. 1.34, p. 14-15; IP Ex. 1.63, pp. 7, 10, 11, 13) Second, many of the G&I assets simply are not severable in a manner that would permit an "allocated portion" of them to be sold to the new owners of IP's generating stations. (Id., pp. 11, 13) As Ms. Carter explained:

> Mr. Lazare appears to believe that if a line of business ceases to exist, that the G&I plant previously allocated to that line of business can also go away, or, stated differently, that the amount of G&I plant which had been allocated to the remaining lines of business would be sufficient to support them. Such a belief is without foundation. For example, bucket trucks and backhoes were allocated in part to the generation function in the 1999 DST case; however, these assets are clearly needed to support the gas, electric transmission and electric distribution businesses. General office buildings and personal computers used by the accounting staff would be other examples of such common, allocable assets. When the Company exited the generation business, the G&I plant that was allocated to the generation function by the labor allocator in the 1999 DST Order did not cease to exist, nor could the portion of G&I plant that had been allocated to the generation

[17] The sale of this building is reflected in IP's pro forma adjustment for facilities no longer in use, discussed in Section II.B.2 of this brief.

> function be somehow broken apart, and sold or transferred to the new owners of IP's generating facilities (other than the specifically identifiable G&I plant which IP in fact transferred to the new owners). Rather, these G&I assets continue to be needed to support the remaining lines of business. (IP Ex. 1.63, pp. 9-10)

As she also explained, "It is the nature of joint and common costs that they are needed to support a single line of business but can also support additional lines of business without any significant increase. *Correspondingly, the elimination of one of several lines of business does not necessarily mean that common costs can be reduced significantly.*" (IP Ex. 1.34, p. 5; emphasis added) Mr. Lazare accepted this proposition in responding to a hypothetical: he acknowledged that if a utility was performing two functions and incurring $100 million of common costs of which $50 million was allocated to each function using the labor allocator, one could not necessarily conclude that if one function were eliminated, the utility could continue to perform the other function while incurring only $50 million of common costs. (Tr. 776)

In essence, Mr. Lazare has treated the Commission's use of the labor allocator in the 1999 DST Case as a determination that a fixed portion of IP's G&I plant assets (and A&G expenses) are permanently and causally associated with IP's former generation assets. Such a belief, of course, is inconsistent with the Commission's statement that "costs associated with general plant may not be amenable to direct assignment to a particular function". (Tr. 748; 1999 DST Order, p. 16) The labor allocator is a technique used to fairly allocate a utility's G&I plant (and A&G expenses) among all its utility functions for costing and ratemaking purposes in setting rates for one of those utility functions. (IP Ex. 1.34, p. 5) However, an allocation of G&I plant using the labor expense allocator in no way establishes an actual causal relationship between the activities of each line of business and the amount of G&I plant (and A&G expense) required to support it. The allocation of common costs among business functions using the labor expense allocator (or similar techniques) does not establish the amount of G&I plant (or A&G expenses) that would be needed to operate a business function on a stand-alone basis.

Mr. Lazare asserted that the fact that Illinois Power divested its generation assets and generation business "did not change the way that the generation utility causes common costs to be incurred". (Staff Ex. 5.0, p. 12) His assertions ignored the fact that during the 2000 test year, IP was no longer a "generation utility", nor did it own the entities which acquired its generation assets and business. Further, although it was indicated in Docket 99-0209, the case in which the sale of IP's fossil generation to DMG was approved, that DMG might for a period of time continue to obtain certain administrative, overhead and support services from IP, it was also indicated in that case that "[i]n the future, [DMG] may develop internal capabilities to provide some or all of these services, or may elect to obtain services from competitive third party providers". (IP Cross Ex. 2, p. 14; see Staff Ex. 5.0, pp. 12-13) In fact, as IP witness Peggy Carter explained in this case, IP did supply such services to DMG for a brief period after the transfer. However, after the Illinova-Dynegy merger was closed in February 2000, many of the administrative and overhead functions that IP was performing for DMG were taken over by Dynegy, including such services as human resources, financial planning and management, cash management and treasury, insurance and claims, internal auditing, public affairs, some legal services and some procurement services. As a result, many of

DMG's administrative support functions are now provided directly by Dynegy. (IP Ex. 1.34, pp. 60-61)

Ms. Carter detailed the services that IP provided to DMG and to AmerGen during the 2000 test year. IP provided services totaling $11,160,347 to AmerGen in 2000 and provided services totaling $9,533,574 to DMG in 2000. (IP Ex. 1.34, pp. 57, 59; IP Exs. 1.56-1.57) Ms. Carter explained that those services still being provided by IP to DMG are priced using fully distributed costs as required in the Services and Facilities Agreement ("SFA") among IP, Dynegy and the other Dynegy subsidiaries that was approved by the Commission in Docket 99-0114.[18] (IP Ex. 1.34, p. 61) She explained the accounting treatment used by IP for revenues received for services provided by IP to AmerGen and to Dynegy and the related costs, and showed that neither the revenues nor the costs were included in setting the distribution revenue requirement in this proceeding. (Id., pp. 57-60; IP Ex. 1.63, pp. 36-37) Neither Mr. Lazare nor IIEC witness Phillips presented any evidence that Illinois Power provided A&G services or G&I facilities to AmerGen or DMG in 2000 for which IP was not properly compensated. (See Tr. 707, 770-73)

**iii. Mr. Lazare's Reliance on Dockets 99-0209 and 00-0802**

In support of his position, Mr. Lazare contended that IP was precluded from increasing the amount of its G&I plant allocated to electric distribution because in Docket 99-0209, the case in which the transfer of IP's fossil generation to DMG was approved, IP made a "commitment" that delivery services rates would not be increased as a result of

[18] Services still provided by IP to DMG include payroll, communications and server usage to support payroll and connections to corporate offices, financial services general consulting, and engineering support. (IP Ex. 1.34, p. 61)

the transfer. (Staff Ex. 14.0, p. 5; see also Staff Ex. 5.0, pp. 9-11) He cited the testimony of Company witness Alec Dreyer in Docket 99-0209 that "Illinois Power's electric customers will see no difference in the level or quality of service they receive, nor will the price they pay increase as a result of the transfer to [DMG]". (Staff Ex. 5.0, p. 10) Mr. Lazare's references to the testimony in Docket 99-0209 do not support his position; indeed, the fact that a few isolated statements from testimony in Docket 99-0209 are among the strongest pillars supporting Mr. Lazare's arguments shows how weak his position is.

As a matter of chronology, IP's §16-111(g) filing to transfer its fossil generating stations to DMG was made on April 16, 1999, the testimony from that case cited by Mr. Lazare was filed shortly thereafter, and the Commission issued its order approving the transfer (including the transfer of the G&I assets listed in the filing) on July 8, 1999. (IP Ex 1.34, pp. 9-10; Tr. 762) Although IP had filed its initial DST case in March 1999, the Commission's order in that case was not issued till August 25, 1999, and the initial provision of delivery services did not commence till October 1, 1999. Thus, at the time the Docket 99-0209 testimony cited by Mr. Lazare was filed, there were no customers taking delivery services or paying delivery services rates; indeed, the Commission had not yet issued its order in the 1999 DST Case adopting the labor expense allocation approach for determining the amount of G&I plant to be included in distribution rate base, and setting the initial DST rates.

More importantly, IP witness Dreyer's statements in Docket 99-0209 were made in the context of attempting to satisfy the two criteria that the Commission has authority to apply in reviewing a §16-111(g) transfer, namely (1) whether the proposed transaction will render the electric utility unable to provide its tariffed services in a safe and reliable manner, and (2) whether there is a strong likelihood that consummation of the proposed transaction will result in the electric utility being entitled to *increase its base rates* during the mandatory transition period pursuant to §16-111(d). (220 ILCS 5/16-111(g); see IP Ex. 1.63, pp. 11-12) Neither of these topics would implicate the level of future delivery services rates. (IP Ex. 1.63, pp. 11-12) It is clear from reading Mr. Dreyer's entire testimony (IP Cross Ex. 2), rather than the limited excerpts cited by Mr. Lazare, that his testimony was addressed to these two statutory criteria, and in particular to the potential impact of the transfer on <u>base rates</u> during the mandatory transition period, not to the level of future DST rates. For example, in summarizing his testimony, Mr. Dreyer stated:

> The PPA [power purchase agreement] between Illinois Power and [DMG] will ensure that Illinois Power will continue to meet its obligation to provide adequate and reliable service to its tariffed service retail customers. Illinois Power's retail electric customers' base rates are frozen through the mandatory transition period ending December 31, 2004, and there is not a strong likelihood that the transfer would result in the Company being entitled to request a base rate increase under Section 16-111(d). Further, Illinois Power has eliminated its fuel adjustment clause. *Therefore, Illinois Power's tariffed service retail customers are insulated from any price risk related to the transfer.* Thus, the Commission should conclude that the transfer meets the standards of Section 16-111(g) of the Restructuring Law. (IP Cross Ex. 2, p. 17-18 (emphasis supplied); see IP Ex. 1.34, p. 10)[19]

[19] The logical conclusion that Mr. Lazare apparently wants to draw from Mr. Dreyer's "commitment" in Docket 99-0209 is that G&I plant (and A&G expense) allocated to "generation" in the 1999 DST case using the labor allocator could not in future DST cases be included in the distribution revenue requirement. However, even if one were to agree with Mr. Lazare that Mr. Dreyer was promising that future DST rates would not be increased as a result of the sale of the fossil generation, and further conclude from that premise that no G&I plant that was allocated to "generation" in the 1999 DST case on the basis of fossil generation labor expense incurred by IP in the 1997 test year in that case can be included in distribution rate base in <u>this</u> case, Mr. Lazare's proposal still would not be supported. Of the $76,240,000 of generation labor expense used in the calculation of labor allocation factors in the 1999 DST Case, $50,539,000 was <u>nuclear</u> generation labor expense. Therefore, approximately 66% of the G&I plant allocated to "generation" in the 1999 DST Case was allocated to nuclear generation; only about 34% was allocated

Mr. Lazare's reliance on Mr. Dreyer's testimony from Docket 99-0209 to support a limitation on the amount of G&I plant (and A&G expenses) that can be included in the distribution revenue requirement in this case is baseless.[20]

Mr. Lazare also contended that IP's allocation of G&I plant (and A&G expense) in this case was inconsistent with Ameren's treatment of G&I plant and A&G expense in its DST case that was filed in December 2000, Docket 00-0802. (Staff Ex. 5.0, pp. 8-9; Staff Ex. 14.0, p. 4) In Docket 00-0802, Ameren allocated a portion of its G&I plant (and A&G expense) to "generation." However, Mr. Lazare ignored the fact that the test year in Docket 00-0802 was a 12-month period ending in 1999, during which the Ameren companies owned and operated generating facilities. Although AmerenCIPS has transferred generating facilities and the generating business to an affiliate, this transfer did not occur until after the period being used as the test year in Docket 00-0802. Thus, under the circumstances of Docket 00-0802, including the test year chosen by the utilities in that case, it was appropriate for Ameren to allocate a portion of G&I plant to the generation business. The facts are different in this docket, however, because IP had exited the generation business prior to the test year used in this case, and during the test

to the fossil generation that was transferred to IP's affiliate, DMG. (IP Ex. 1.63, p. 12) Mr. Lazare has identified no similar "commitment" made in connection with the sale of the nuclear generation to AmerGen.

[20] Mr. Lazare also contended that the increases in G&I plant and A&G expense in the distribution revenue requirement in this case over the 1999 DST Case were inconsistent with estimates made at the time of the Illinova-Dynegy merger as to the savings that would result from the merger. (Staff Ex. 5.0, pp. 13-15) Since this contention relates primarily to A&G expenses, it is addressed in Section II.C.3.e below relating to A&G expenses and charges from Dynegy.

year used in this case owned essentially no generation and had essentially no generation–related labor expense. (IP Ex.1.34, pp. 8-9; IP 1.63, pp. 14-15; Tr. 760-61)

### iv. IP's G&I Plant Balances are Reasonable

IP Exhibit 1.39 detailed the changes in Illinois Power's G&I plant accounts on a year-by-year basis from December 31, 1997 (the end of the test year used in the 1999 DST case) to December 31, 2000 (the end of the test year in this case). Overall, the original cost of plant in service recorded in Accounts 301-303 and 389-399 increased from $371.1 million at December 31, 1997 to $385.0 million at December 31, 2000, an increase of about $14 million (3.7%).[21] (IP Ex. 1.34, p. 17) Although, as described above, IP transferred approximately $55 million of G&I plant to DMG and AmerGen in 1999, the Company has continued to make necessary and reasonable investments in G&I plant from December 31, 1997 through December 31, 2000. (Id.) In this case, IP explained and justified its individual additions to G&I plant costing in excess of $250,000 that were placed in service between December 31, 1997 and December 31, 2000. (Corrected IP Exs. 1.32-1.33; Corrected Rev. IP Exs. 2.4-2.5) The Company also described the additions to G&I plant to be placed in service between January 1, 2001 and June 30, 2002, that IP is proposing to include in rate base in this case. (Corrected Rev. IP Ex. 1.5, IP Ex. 1.64, Corrected Rev. IP Exs. 2.8-2.9, IP Exs. 2.15 and 2.19-2.20; see Section II.B.3.a above) No witness contended that any of these G&I capital additions

[21] These figures are the original cost of G&I plant in service as recorded in the utility plant accounts at the various dates shown on IP Ex. 1.39, and do not include accumulated depreciation and the deferred tax reserves associated with these assets. The net amount of G&I plant would be less than these numbers due to the associated accumulated depreciation and deferred tax reserves at December 31, 1997, and the growth in the accumulated provision for depreciation and deferred tax reserves from December 31, 1997 to December 31, 2000.

projects (either the ones placed in service in 1998-2000, or the ones being placed in service in 2001-2002) were imprudent, excessive or unnecessary.

Moreover, in the 1999 DST Case, IP presented evidence to describe and justify significant G&I plant additions that had been made or were planned subsequent to 1992, when an electric rate base was last established for the Company, through 2000. (IP Ex. 1.34, p. 7) Thus, through its evidence in the 1999 DST Case and in this case, IP has justified its major G&I plant additions from at least 1992 through 2001-2002. (IP Ex. 1.63, pp. 17-18) Neither Mr. Lazare nor Mr. Phillips identified any specific items of G&I plant that they contended were imprudent, unnecessary to support the distribution business or that otherwise should not be included in rate base. (IP Ex. 1.34, pp. 17, 20; IP Ex. 1.63, pp. 15-16; Tr. 778-780)

Illinois Power properly determined the amount of G&I plant that should be included in distribution rate base using the labor allocation expense approach adopted by the Commission in the 1999 DST Case. No party identified any errors in IP's calculation of the labor expense allocation factors. IP also justified the overall level of its G&I plant accounts; the Company showed that it transferred $55 million of G&I plant to the parties that acquired its generating stations, and that it has taken other actions to reduce its level of G&I plant where possible. No party identified any items of G&I plant (either those in service at December 31, 2000, or those being placed in service between January 1, 2001 and June 30, 2002) that are imprudent, unreasonable or unnecessary. The only basis for the limitations on the amount of G&I plant in rate base proposed by Messrs. Lazare and Phillips is that the Company should allocate a portion of G&I plant to a generation business that it no longer owns nor is engaged in. These witnesses' positions display a fundamental misunderstanding of the nature of common costs; further, they have not refuted the Company's showing that its remaining G&I assets are needed to support its existing businesses of gas, electric transmission and electric distribution. Nor have they identified any G&I plant items included in distribution rate base that are not needed to support the distribution business. Mr. Lazare's and Mr. Phillips' positions should be rejected, and the balances of G&I plant that Illinois Power proposes to include in distribution rate base should be accepted by the Commission.

#### d. Capitalization of Severance Costs

During the test year IP incurred costs for severance and early retirement programs that resulted in elimination of 297 employees. The costs were charged to A&G accounts 920 (Administrative & General Salaries) and 926 (Employee Pensions and Benefits) under the USOA. Prior to these employees being terminated or accepting early retirement, the compensation of many of them had also been recorded to Account 920. In accordance with the standard accounting practice, IP capitalized a portion of these administrative costs. Since the severance costs were incurred to eliminate positions that were no longer required, IP concluded it was appropriate to account for these costs in the same manner as the cost that was eliminated, i.e., the compensation of the terminated employees. Accordingly, the Company capitalized a portion of these A&G costs and recorded the remainder as expenses, consistent with its usual practice with respect to costs charged to Accounts 920 and 926. (IP Ex. 1.34, pp. 25-26; IP Ex. 1.63, pp. 23-24)

Staff witness Dianna Hathhorn objected to any recovery of the severance and early retirement program costs. Recovery of the expense component of these costs is discussed in Section II.C.3.b of this Brief. This section discusses Ms. Hathhorn's contention that under the USOA, no portion of the severance and early retirement program costs should have been capitalized (even if the Commission concludes that such costs are recoverable in rates). (Staff Ex. 1.0, pp. 17-18; Rev. Staff Ex. 10.0, pp. 11-13) For the reasons shown in this section, Ms. Hathhorn's position is not well-founded; IP properly capitalized a portion of the severance and early retirement program costs.

The essence of Ms. Hathhorn's position is that severance and early retirement costs are not labor costs incurred by the utility in connection with construction and are not related to construction.[22] (Rev. Staff Ex. 10.0, pp. 11-13) However, a careful review of the nature of these costs and the relevant provisions of the USOA shows that IP's capitalization of a portion of the costs was proper.

Ms. Hathhorn relied on subsection (A)(2) of Electric Plant Instruction No. 3 of the USOA, which states that the cost of construction properly includible in the electric plant accounts shall include (among other things), "Labor":

> (2) Labor includes the pay and expenses of employees of the utility engaged on construction work, and related workmen's compensation insurance, payroll taxes and similar items of expense. It does not include the pay and expenses of employees which are distributed to construction through clearing accounts nor the pay and expenses included in other items hereunder. (See Rev. Staff Ex. 10.0, pp. 11-12)

However, as Ms. Hathhorn agreed, Electric Plant Instruction No. 3, subsection (A)(2) refers to the pay and expenses of the employees who are directly engaged in performing the construction work, i.e., the construction labor. (Tr. 309-310) Therefore, subsection (A)(2) is not really relevant to the treatment of A&G costs. Ms. Hathhorn also acknowledged that Electric Plant Instruction No. 3, subsection (12), includes in construction costs the pay and expenses of general officers and general and

[22] The severance payments clearly were labor costs. They were included as taxable wages for the severed employees. (IP Ex. 1.63, p. 23)

administrative expenses applicable to construction work. (Tr. 309) In addition to Electric Plant Instruction No. 3, Electric Plant Instruction No. 4 provides for the recording of "overhead construction costs," including "general office salaries and expenses" and "relief and pensions". (Rev. Staff Ex. 10.0, p. 12; Tr. 310-11) Ms. Hathhorn acknowledged that "general office salaries and expenses" and "relief and pensions" as referred to in Electric Plant Instruction No. 4 are the costs which, if they were being expensed, would be recorded in, respectively, Account 920, Administrative and General Salaries, and Account 926, Employee Pensions and Benefits. (Tr. 310-11)

Ms. Hathhorn also noted that Electric Plant Instruction No. 4 of the USOA requires that "overhead construction costs" shall either be "charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto", or, where a direct charge procedure is impractical, "special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized." She observed that under Electric Plant Instruction No. 4, "The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted." (Rev. Staff Ex. 10.0, p. 13) IP complied with this Instruction. Specifically, IP annually determines the percentage of costs recorded in Account 920 to be capitalized based on a study of the level of support provided to other business functions; based upon the study, a percentage of A&G to be capitalized is determined and applied to applicable costs. IP used this percentage to determine the amount of severance costs to be capitalized, consistent with its treatment of all other A&G costs. IP also used the same percentage of the early retirement costs to be capitalized that it used in capitalizing all other costs charged to Account 926. (IP Ex. 1.63, pp. 23-24)

Ms. Hathhorn agreed that IP allocates a portion of A&G costs to construction on the basis of periodic studies as described in Electric Plant Instruction No. 4, and that IP used the same percentage to allocate a portion of the severance and early retirement costs to construction that it used to allocate other costs recorded in Accounts 920 and 926 to construction. (Tr. 311-12) She stated that she did not take issue with the percentage used by IP in 2000 to allocate a portion of its A&G costs to construction. (Tr. 312)

In summary, IP properly capitalized a portion of the severance and early retirement costs. Given Ms. Hathhorn's recognition that these costs were properly chargeable to A&G Accounts 920 and 926, it was appropriate to capitalize a portion of these costs on the same basis as all other costs charged to Accounts 920 and 926. Further, the Company properly determined the portion of A&G costs to be capitalized on the basis of special studies, and applied the same percentage to the severance and early retirement costs as to all other costs recorded in, respectively, Accounts 920 and 926. Ms. Hathhorn did not take issue with IP's procedures for conducting such studies or with the resulting capitalization percentages. Accordingly, Ms. Hathhorn's position that the Company should not have capitalized any portion of the severance and early retirement costs must be rejected.

#### e. Deferred Tax Debit Balances

CUB/AG witness Effron proposed to remove from the reserve for deferred income taxes the debit balances for four items in the deferred tax accounts. (GCI Ex. 2.0, pp. 27-29) In the determination of rate base, the accumulated reserve for deferred income taxes is deducted, thereby reducing the size of rate base. However, deferred tax debit balances reduce the size of the overall deferred tax reserve (in contrast to credit balances, which increase the size of the deferred tax reserve). Therefore, by removing certain deferred tax debit balances in the calculation of rate base, Mr. Effron's adjustment would have the effect of increasing the amount of the reserve for deferred taxes, and therefore decreasing overall rate base. (See Tr. 407-09)

Mr. Effron's rationale for removing the four deferred tax debit balances he chose to remove was that these deferred tax debit balances "are related to reserves, deferred credits, or accrued liabilities that are not recognized in the calculation of rate base".[23] (GCI Ex. 2.0, p. 28; Tr. 409) However, his proposed adjustment departs from the underlying rationale for deducting the reserve for deferred taxes in determining rate base. The overall deferred tax reserve consists of numerous individual debit and credit balances relating to book versus tax timing differences that arise for a wide variety of reasons. From a balance sheet perspective, accumulated deferred income taxes support a portion of the utility's assets. (Tr. 412) As Mr. Effron acknowledged, accumulated deferred income taxes are deducted from rate base because they constitute ratepayer-supplied capital, not investor-supplied capital; the theory is that a utility should not be allowed to earn a return on the portion of its assets in rate base that are not supported by investor-supplied capital. (Id.; IP Ex. 1.34, p. 28) Therefore, the entire net balance of the

[23] The four items are the deferred tax debit balances related to accrued pensions and benefits, miscellaneous reserves, vacation pay accrual, and accrued interest on tax liabilities. The item relating to accrued pensions and benefits consists of a debit balance relating to pension/expense funding and a credit balance relating to OPEB expense/funding, with the net being a debit balance. (GCI Ex. 2.0, pp. 28-29, and Sched. DJE-6.4; see IP Ex. 1.69)

accumulated reserve for deferred taxes should be deducted from rate base, without adjustment.

It has not been the Commission's practice to determine the components of the deferred tax reserve to be deducted from rate base on an account-by-account basis. Rather, the Commission has simply deducted the entire deferred tax reserve from rate base. Mr. Effron has previously attempted a selective exclusion from the deferred tax reserve for rate base purposes, without success. In Illinois Power's 1989-1990 rate case, Docket 89-0276, Mr. Effron opposed the inclusion in rate base of the deferred tax balance associated with the phasing of unbilled revenues into taxable income. The Commission concluded:

> The Commission concludes that since this deferred tax is like any other deferred tax, arising out of a timing difference between the book treatment and tax treatment of the same expense or income item, it should be treated like other deferred taxes for ratemaking purposes and be reflected in the calculation of IP's rate base. (Order in Docket 89-0276 (June 6, 1990), pp. 94-95)

The Commission should reach the same result here. The entire balance of the reserve for deferred taxes should be deducted from rate base, without selective adjustment for individual items.

#### f. <u>Incentive Compensation Capital Adjustment</u>

During the test year, Illinois Power made payments to its employees under its incentive compensation program. A portion of the incentive compensation paid to employees was capitalized and charged to construction; the balance was expensed. Staff witness Hathhorn proposed that incentive compensation payments be disallowed for ratemaking purposes. (Staff Ex. 1.0, pp. 26-32) As part of her adjustment, she proposed that the portion of incentive compensation payments that was capitalized and charged to construction should be removed from rate base. (Id., p. 32; Staff Sched. 19.4, col. (c)) Ms. Hathhorn's proposed disallowance of incentive compensation expense is discussed in Section II.C.3.a of this Brief. As shown therein, her proposed adjustment to disallow incentive compensation expense should be rejected. Accordingly, her adjustment to disallow the capitalized portion of incentive compensation should also be rejected.

### C. Distribution Operating Expenses

#### 1. Overview of IP's Proposed Operating Expense Statement

Illinois Power proposes the following distribution operating expense statement (Rev. IP Ex. 3.24):

| Item | Amount (000) |
|---|---|
| Operation and Maintenance | $53,015.0 |
| Customer Accounts Expense | 12,163.0 |
| Customer Service and Inform. Expense | 4,488.0 |
| Administrative & General Expense | 41,682.0 |
| Depreciation Expense – Dist. Plant | 33,789.0 |
| Depreciation Expense – General Plant | 5,189.0 |
| Amortization Expense – Intangible Plant | 7,106.0 |
| Taxes Other Than Income Taxes | 33,287.0 |
| Investment Tax Credit Adjustment – Net | ( 573.0) |
| Total Operating Expenses | $190,146.0 |

#### 2. Uncontested Adjustments to Distribution Operating Expenses

Illinois Power's proposed operating expense statement incorporates a number of adjustments that were proposed by the Company and not opposed by any other party, as well as a number of adjustments that were proposed by other parties and accepted by the Company. The following paragraphs summarize these uncontested adjustments.

**Load research project.** The operating expenses include an ongoing level of expense necessary in connection with IP's load research project (described in Section

II.B.2 above). The annual O&M expense consists principally of telephone charges for cell phones installed on the load research meters to enable the data they collect to be accessed. This adjustment also includes the depreciation expense on the load research meters. This adjustment increases distribution operating expense by $182,000. (IP Ex. 6.1, p. 28; IP Ex.6.5; IP Ex. 1.75; Rev. IP Ex. 3.24, p. 1, col. (5))

**CWIP transferred to Utility Plant in Service.** In connection with the uncontested rate base adjustment to transfer to plant in service accounts the costs of certain projects that were still recorded in the CWIP accounts at December 31, 2000, but had already been placed in service (see Section II.B.2 above), there are also additional operating expenses, principally for depreciation and taxes other than income taxes. This adjustment recognizes these amounts as plant in service. (IP Ex. 1.1, p. 11) The adjustment increases distribution operating expense by $839,000. (Corrected Rev. IP Ex. 1.7; IP Ex. 1.75; Rev. IP Ex. 3.24, p. 1, col. (7))

**Facilities no longer in use.** In connection with the rate base adjustment to remove Company facilities no longer in use, there are also reductions to A&G expense, depreciation expense and taxes other than income taxes. This adjustment reduces distribution operating expense by $418,000. (IP Ex. 1.1, pp. 11-12; IP Ex. 2.1, p. 19; IP Exs. 1.29, 1.75; Rev. IP Ex. 3.24, p. 1, col. (8))

**Rate case expense.** This adjustment provides for the amortization and recovery of the costs of outside services for this case over a three-year period, which is the same amortization period allowed for rate case expenses in the 1999 DST Case. This adjustment also provides for recovery of the remaining unamortized balance of expenses from the 1999 DST Case. This adjustment increases distribution operating expense by $494,000. (IP Ex. 1.1, pp. 17-18; IP Ex. 1.16; Rev. IP Ex. 3.24, p. 1, col. (10))

**Postal rate increase.** This adjustment increases Customer Accounts expense for the amount of the postal rate increase (one cent per letter for first class and bulk mailings) that went into effect on January 1, 2001. This adjustment increases distribution operating expense by $68,000. (IP Ex. 1.1, p. 18; IP Ex. 1.17; Rev. IP Ex. 3.24, p. 1, col. (11))

**Insurance expense.** This adjustment revises the test year amount of insurance expense in three respects. First, it recognizes premium increases in 2001 for property and liability insurance over 2000. Second, it removes certain one-time credits to nuclear insurance premiums that IP received in 2000, which served to understate the ongoing level of insurance expense. Third, it removes the expense incurred in 2000 for a residual nuclear policy maintained by IP. This adjustment increases distribution operating expense by $2,619,000 in the aggregate. (IP Ex. 1.1, pp. 19-20; IP Ex. 1.18; Rev. IP Ex. 3.24, p. 1, col. (12))

**Company use of electricity.** Because IP no longer owns generating facilities, it must purchase the electricity it uses at its facilities from third parties. This adjustment provides for the cost of Company use of electricity in distribution operating expenses. The adjustment increases operating expense by $1,127,000. (IP Ex. 1.1, pp. 21-22; Rev. IP Ex. 1.24; Rev. IP Ex. 3.24, p. 2 col. (16))

**Pass-through revenue taxes.** This adjustment eliminates from distribution operating expense (taxes other than income taxes) $12,067,000 of municipal utility taxes, public utility taxes, Low Income Energy Assistance charges and Renewable Energy Fund charges that IP collects from retail customers as agent for municipal and State governmental authorities. (IP Ex. 1.1, p. 22; IP Ex. 1.25; Rev. IP Ex. 3.24, p. 2, col. (17))

**Payroll expense adjustment for wage and salary increases.** This adjustment increases distribution operating expense by $1,410,000 to reflect a scheduled 3% union wage increase that was effective July 1, 2001, and a corresponding salary increase for non-union employees provided in 2001. The final adjustment amount incorporates revisions suggested by Staff witness Hathhorn. (IP Ex. 1.1, pp. 22-23; IP Ex. 1.34, p. 29; IP Ex. 1.76; Rev. IP Ex. 3.24, p. 2, col. (18))

**FICA expense.** This adjustment increases distribution operating expense by $52,000 to reflect the employer's responsibility to match a higher portion of the employees' FICA contributions in 2001 (6.2% of first $80,000 of gross earnings versus 6.2% of first $76,000 of gross earnings in 2000). (IP Ex. 1.1, p. 23; IP Ex. 1.27; Rev. IP Ex. 3.24, p. 2, col. (19))

**Dynegy senior executive bonuses.** This adjustment reduces distribution operating expense by $7,445,000 to remove the expense of bonuses accrued in 2000 for Dynegy executives that was allocated to IP. (IP Ex. 1.1, p. 24; IP Ex. 1.77; Rev. IP Ex. 3.24, p. 2, col. (21))

**Operations compliance program.** This adjustment increases distribution operating expense by $77,000 to provide for the amortization over a three-year period of a $230,000 expense that IP incurred for an outside consultant in connection with the initial establishment of its operations compliance program. The operations compliance group will monitor and provide feedback regarding IP's adherence to operating procedures, standards and policies, and define and improve IP's processes for maintaining compliance with these requirements. (IP Ex. 2.1, p. 20; Rev. IP Ex. 3.24, p. 2, col. (22))

**<u>Storm damage expense normalization</u>.** This adjustment increases distribution operating expense by $581,000 to provide for a normalized level of storm damage expense. The adjustment is based on the difference between actual 2000 storm damage expense and the average expense for the five-year period 1996-2000. (IP Ex. 2.1, pp. 20-21; IP Ex. 2.11; Rev. IP Ex. 3.24, p. 2, col. (23))

**<u>"Duke Engineering" litigation expense</u>.** This adjustment reduces distribution operating expense by $1,030,000 to remove the expense incurred in 2000 for a litigation matter that arose in connection with IP's ownership of Clinton Power Station. This adjustment was proposed by CUB/AG witness Effron. Consistent with this adjustment, any recoveries IP ultimately realizes in this litigation will also be recorded below the line. (IP Ex. 1.63, p. 25; Rev. IP Ex. 3.24, p. 3, col. (27))

**<u>Edison Electric Institute dues attributable to lobbying activities</u>.** This adjustment reduces distribution operating expense by $14,000 to remove the portion of IP's dues paid to the Edison Electric Institute that were used for that organization's lobbying activities. This adjustment was proposed by Commission Staff witness Bonita Pearce. (IP Ex. 1.34, p. 30; Staff Ex. 3.0, pp. 5-6; Rev. IP Ex. 3.24, p. 3, col. (28))

**<u>Correction to billings from Dynegy under the SFA</u>.** This adjustment reduces distribution operating expense by $1,035,000 to reflect a correction to IP's billings from Dynegy for allocated A&G costs. The need for this correction was identified by Staff witness Hathhorn, who pointed out that certain corporate A&G costs were not allocated to IP in 2000 using the correct allocation formula specified in the SFA. (IP Ex. 1.34, p. 30; Staff Ex. 1.0, p. 32; Rev. IP Ex. 3.24, p. 3, col. (30))

**Reimbursements to Clinton Power Station employees.** This adjustment reduces distribution operating expense by $2,000 to eliminate certain expense reimbursements that were paid in 2000 to Clinton Power Station employees. This adjustment was identified by Staff witness Hathhorn. (IP Ex. 1.34, p. 29; Staff Ex. 1.0, p. 14; Rev. IP Ex. 3.24, p. 3, col. (31))

**Metering and billing expense for additional customers.** The Company accepted an adjustment to test year billing determinants proposed by CUB/AG witness Effron that increased the number of customers by 3,404. (IP Ex. 6.6, pp. 3-4) This adjustment increases customer accounts expense by $33,000 for the additional meter reading and billing expenses that would be incurred as a result of such an increase in the number of customers. (IP Ex. 8.10, pp. 8-9; IP Ex. 8.13; Rev. IP Ex. 3.24, p. 3, col. (32))

**Payments to State of Illinois Energy Efficiency Fund.** This adjustment reduces Customer Service and Information expense by $446,000 to remove IP's pro rata portion of the annual aggregate $3,000,000 contribution that must be made by sellers of electricity to the State's Energy Efficiency Trust Fund. Staff witness Pearce identified the need for this adjustment. IP will instead impose a per-kWh charge in those DST-related tariffs in which it sells electricity (i.e., Rider PPO and Rider ISS) to recover the portion of this payment attributable to energy sales to delivery services customers. (IP Ex. 1.34, p. 30; Staff Ex. 3.0, pp. 6-7; IP Ex. 5.11, p. 2; Rev. IP Ex. 3.24, p. 3, col. (33))

**Illinois Energy Association dues.** This adjustment reduces distribution operating expense by $72,000 to remove dues paid to the Illinois Energy Association, as recommended by Staff witness Pearce.[24] However, as discussed in Section II.C.3.h below, the Company contests the remainder of Ms. Pearce's adjustment for contributions to community organizations. (IP Ex. 1.63, pp. 25, 41-42; IP Ex. 1.73; Rev. IP Ex. 3.24, p. 3, col. (34))

### 3. Contested Adjustments to Operating Expense

#### a. Incentive Compensation Expense

##### i. Incentive Compensation Costs are a Reasonable and Necessary Business Expense that Must be Included in Setting Rates

The Company's proposed test year distribution operating expenses include $5,159,000 of expense for payments to employees under IP's incentive compensation program. This is the electric distribution portion of IP's total test year incentive compensation expense. Staff witness Hathhorn proposed to disallow this expense.[25] (Staff Ex. 1.0, pp. 26-32 and Sched. 1.13) CUB/AG witness Effron proposed to disallow all but $596,000 of this expense.[26] (GCI Ex. 4.0, pp. 8-9) The Hathhorn and Effron adjustments should be rejected.

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[24] Ms. Pearce showed the amount of the adjustment for Illinois Energy Association dues to be $44,000. (See Staff Ex. 3.0, p. 4 and Sched. 3.1, and Tr. 267)

[25] Ms. Hathhorn also proposed to disallow $434,000 of depreciation and amortization expense representing depreciation of the portion of incentive compensation costs that were capitalized; and $485,000 of payroll taxes on the incentive compensation payments to employees. (See Staff Sched. 1.13 and 19.2)

[26] Mr. Effron did not propose his adjustment until his rebuttal testimony. He would allow recovery of $596,000 of the incentive compensation expense because this amount was awarded based on safety and reliability objectives, whereas the remainder was awarded based on the achievement of corporate earnings goals that, according to Mr. Effron, benefit shareholders not customers. (GCI Ex. 4.0, pp. 8-9) The $596,000 amount is the jurisdictional portion of incentive compensation paid to IP's union employees.

Incentive compensation programs are commonly used in American business today as part of an entity's total compensation program. Incentive compensation programs provide a cost-effective way to attract and retain qualified employees, particularly employees in those job categories for which the employment market is highly competitive. IP has had an incentive compensation program in place as part of its overall compensation structure since at least 1991, and has made incentive compensation payments to employees in each year in this period. (Rev. IP Ex. 10.1, p. 2) Incentive compensation payments now constitute a material part of IP's overall compensation expense.[27] Further, use of an incentive compensation program provides benefits to both Illinois Power and its customers. IP's incentive compensation costs are a reasonable and necessary business expense incurred in providing service to customers. The Company is entitled to have its rates set so as to allow it a fair opportunity to recover its reasonable and necessary expenses. To allow no recovery of incentive compensation expense, as proposed by Ms. Hathhorn, or less than 15% of the test year expense, as proposed by Mr. Effron, would be arbitrary and would deny IP recovery of a reasonable and necessary expense.

For 2000 and 2001, the basic structure of IP's incentive compensation program for non-union employees had these components:

[27] IP's jurisdictional incentive compensation cost in 2000 was $6,338,000 (Staff Ex. 1.0, p. 30), of which $596,000 was paid to union employees (see above) and the remaining $5,742,000 was paid to non-union employees. The Company's total base pay to non-union employees was $45.0 million (Rev. IP Ex. 10.1, p. 12); based on the electric distribution allocation factor of 0.579 (IP Ex. 1.4), $26,055,000 of this amount is electric distribution jurisdictional. Therefore, incentive compensation constituted about 18% of the total compensation of non-union employees (i.e., $5,742,000 divided by the sum of $26,055,000 plus $5,742,000).

- The overall funding of the program was based on the extent to which IP met one or more pre-established corporate performance targets of the Company or its corporate parent, Dynegy (and therefore, necessarily, of Dynegy's other affiliated companies).

- The individual incentive compensation payments to non-union employees from the overall fund were based on the extent to which employees met individual and/or departmental goals and objectives. Individual employee goals established to use in determining the extent of the employee's incentive compensation payment from the overall pool include budgetary and cost control objectives, safety, reliability and project completion objectives, and skills development objectives.

- IP also considered the labor market for each category of employees in determining individual employee payments, thereby further enhancing the usefulness of the program in retaining qualified employees in fields for which the labor market is highly competitive. (Rev. IP Ex. 10.1, pp. 3, 14)

The Company had a separate program for determining incentive compensation payments to its union employees, which had been negotiated in the current collective bargaining agreement. (Id., pp. 3, 13)

Illinois Power notes that the Commission has denied recovery of incentive compensation expense in a number of prior cases, generally citing the same set of generic reasons. Although Staff witness Hathhorn did not dispute that an incentive compensation program provides benefits for the Company (Tr. 330), she relied on these prior cases in support of her adjustment. Illinois Power, however, urges the Commission to take a fresh look at the entire topic of incentive compensation, its importance in the Company's overall compensation structure, and the benefits it provides to both the Company and its customers. IP urges the Commission to recognize that incentive compensation is a reasonable and necessary business expense and that as a result, <u>some</u> provision for incentive compensation costs must be allowed in setting rates.

The record in this proceeding shows that incentive compensation programs have become commonplace among U.S. businesses. Use of incentive compensation programs as part of a total compensation package to attract and retain qualified employees is a common business practice. (IP Ex. 1.34, p. 41) IP witness Ellen Hearn, who is employed in the Company's Human Resources department and has extensive experience in human resources for a number of companies, testified that:

> Working as a human resources professional with a number of regulated and unregulated companies in various industries, I have found that most companies now use incentive compensation programs as part of their overall compensation structures. A company without an incentive compensation program is the exception, not the rule.[28] (Rev. IP Ex. 10.1, p. 4)

In IP's experience, the incentive compensation program is an important and useful tool in attracting and retaining high-quality employees, particularly for positions for which there is a highly competitive employment market. Positions for which the labor market has been highly competitive in recent times include electrical engineers, accounting professionals, information technology ("IT") professionals, and lineman candidates. (Rev. IP Ex. 10.1, p. 8) IP must attract and retain qualified employees in these and other fields if it is to meet its service obligations and requirements in a safe and reliable manner, and must offer competitive compensation packages to prospective and current employees in order to attract and retain them. (Id.) Further, Illinois Power does not just compete with other regulated utilities for employees; rather, it competes for employees with other businesses in the energy industry as well as with other unregulated businesses in general. (IP Ex. 10.2, pp. 5-7; Tr. 331-32) In addition, IP has experienced

[28] Ms. Hearn cited a number of studies and articles that illustrated the widespread use of incentive compensation programs. (See Rev. IP Ex. 10.1, pp. 3-4; IP Ex. 10.2, pp. 5-7; see also Tr. 302-03)

difficulties in attracting employees to live and work in Decatur and other central Illinois locations. (Rev. IP Ex. 10.1, pp. 7-8) An incentive compensation plan enables IP to offer prospective and current employees the opportunity for additional compensation beyond their base salary and wage amounts, with upside potential based on corporate and individual performance. (Id., p. 7) Moreover, because incentive compensation programs are widespread, prospective employees considering whether to join IP, and current employees considering whether to leave IP for other employers, may consider IP's program and compare it to those offered by other prospective employers.[29] (Id.)

The incentive compensation program is also valuable to Illinois Power because it can be structured so as to focus employees' attention and performance on business issues that are critical to the Company at the time. IP can focus the employees' efforts and attention on the Company's current business needs by the selection of the corporate goals and objectives on which overall incentive compensation funding and/or payments to individual employees will be based. The ability to modify the bases for funding and awarding incentive compensation from year to year is one of the strengths of the program. (Rev. IP Ex. 10.1, pp. 5-6)

[29] One of Staff witness Hathhorn's concerns is that under IP's incentive compensation programs in 2000-2001, the total amount of money made available for distribution to employees is based, in whole or in part, on the financial performance of IP's corporate parent, Dynegy, Inc., and its other, unregulated affiliates. As Ms. Hearn explained, however, this aspect of IP's program is an advantage because it enhances the usefulness of incentive compensation as a tool to attract and retain qualified employees. Prior to the merger with Dynegy, prospective and existing employees may have seen the upside potential from IP's incentive compensation program as limited because it was solely dependant on the financial performance of a regulated utility, IP. In contrast, the ability to base the program funding on the financial performance of Dynegy enables IP to offer employees the opportunity to participate in the upside potential of a diversified Fortune 500 company that is a recognized leader in several businesses. (Rev. IP Ex. 10.1, pp. 8-9; IP Ex. 10.2, p. 3)

Use of incentive compensation as part of the Company's overall compensation package enables IP to offer additional compensation to attract and retain employees, and to focus employees' attention on corporate or individual business needs and objectives of current importance, without locking in higher levels of base pay and related benefits costs. As Ms. Hearn explained, when employees receive annual wage and salary increases, they tend to expect the new level of pay each year, and to view the annual pay increases as a locked-in floor to their compensation. Such expectations, however, are not associated with incentive compensation payments. As a result, the incentive compensation program can be used to reward employees for strong corporate performance and/or strong individual performance in a particular year without creating the expectation that the same level of pay will be received in future years. (Rev. IP Ex. 10.1, p. 10) In addition, pension and benefit program costs are tied to the employees' base wage and salary levels, but are not affected by incentive compensation payments. Therefore, incentive compensation payments do not result in increased pension and benefits costs to IP. In contrast, a corresponding amount of employee base pay would result in additional pension and benefit program costs. (Id., p. 11)

The benefits of the incentive compensation program to the Company also result in benefits to its customers. First, the incentive compensation program enhances IP's ability to attract and retain qualified employees, which benefits customers. Second, the desire to achieve both the overall corporate performance objectives, which determine the overall amount of funding for the program, and the individual performance goals and objectives, which determine the individual employee's payout, help motivate employees to achieve a higher level of performance. Individual goals are based on objectives such as meeting budget and cost control targets, safety, reliability and project completion targets, and skills development objectives, all of which can benefit customers in terms of maintaining or improving levels of safety and reliability, or controlling cost levels and thereby deferring future rate increase requests. Third, the incentive compensation program addresses these objectives without requiring increases in base pay and related pension and benefits costs, thereby helping to reduce the need for increases in costs that in the long run would need to be reflected in customer's rates. (IP Ex. 10.1, pp. 11-12)

#### ii. The Objections Raised by Ms. Hathhorn and Mr. Effron Do Not Justify their Proposals to Allow Little or No Recovery of Incentive Compensation Costs

The principal objections raised by Ms. Hathhorn to including incentive compensation expense in the revenue requirement are (1) the program funding is determined by the extent to which corporate financial targets of IP and Dynegy (and therefore of other Dynegy affiliates) are achieved, which benefits shareholders, not customers, (2) including incentive compensation expense in setting rates leaves customers "unprotected" because if the same level of incentive compensation expense is not incurred in a subsequent year, customers' rates will reflect a cost item the Company does not incur, and (3) based on the historical year-to-year variation in incentive compensation payments, it is not possible to determine a "normal" amount of incentive compensation expense.[30] Mr. Effron's opposition is based, essentially, on item (1).

[30] Ms. Hathhorn also stated an additional objection, that "deficiencies cited in prior Commission orders disallowing the Company's [incentive compensation] expense have not been addressed". (Staff Ex. 1.0, p. 27) However, review of her testimony shows that the "deficiencies" are essentially the same points as objections (1) and (2).

(Staff Ex. 1.0, pp. 26-32; GCI Ex. 4.0, pp. 8-9) These objections do not warrant disallowing recovery of this reasonable and necessary business expense.

As to the first objection, the incentive compensation program provides benefits to customers, as described earlier in this section. Focusing on the fact that the program is funded based on the achievement of overall corporate financial objectives misses the point. Corporate financial performance is simply the overall target that is used to determine the funding of the overall incentive compensation pool for distribution. The incentive compensation program benefits customers because it motivates and focuses employees to control costs and meet budget objectives (to help increase the funding of the overall pool), it enhances IP's ability to attract and retain qualified employees, it enables IP to provide market-based compensation without locking in base pay increases or incurring related pension and benefits costs, and it motivates employees to meet the individual employee goals (on which individual payments are based) that stress safety, customer service, reliability and cost control. (IP Ex. 10.2, pp. 1-2)

As to the second objection, the risk perceived by Ms. Hathhorn that in a future year no incentive compensation payments will be made is belied by the facts that (1) IP has made incentive compensation payments to its employees for every year since 1991 (Rev. IP Ex. 10.1, p. 2), and (2) as described above, incentive compensation programs are now commonplace among American businesses, and an integral part of IP's overall compensation structure. Moreover, the risk that in a future year an expense amount that was included in setting rates will not be incurred, or will be incurred in lesser amount, whether through the impact of external forces or through intentional management action, is by no means unique to incentive compensation costs. Between rate cases, the size of the work force can be reduced, materials and supply contracts can be renegotiated, assets can be sold or retired, debt can be refinanced at lower interest rates, the price of gasoline needed to fuel company vehicles can drop – any of these events will leave the utility charging rates that recover costs the utility is no longer incurring. In sum, the "ratepayer protection" argument does not justify denying recovery of incentive compensation costs.

The foregoing having been said, Illinois Power acknowledges that the jurisdictional amount of incentive compensation expense for 2000 was the highest amount in the five-year period 1996-2000.[31] (See IP Ex. 1.34, p. 42; IP Ex. 1.47) While it would be arbitrary and unreasonable to assume that there is any meaningful likelihood of zero incentive compensation costs being incurred in a future year, the Commission might conclude that the 2000 expense amount was unusually high and should be normalized in some manner. To that end, the Company offered four alternative adjustments to incentive compensation expense that would provide for a lesser amount of incentive compensation expense in the test year distribution revenue requirement. These alternatives are discussed in subsection (iii) below.

As to the third objection, it should be no more difficult to determine a "normal" amount of incentive compensation expense for ratemaking purposes than it is for other reasonable and necessary operating expenses that tend to vary (both up and down) from year to year. For example, in this case, IP has proposed, and the parties have accepted, an adjustment to increase the actual 2000 level of storm damage O&M expense to a "normal" level based on a five-year average of storm damage expenses. (See IP Ex. 2.11

[31] The test year, 2000, was a year of strong financial performance for IP and the Dynegy organization, resulting in a high level of funding of the incentive compensation pool. (IP Ex. 1.63, pp. 31-32)

and Section II.C.2 above) The annual amounts of storm damage direct expense incurred by the Company over the five years 1996-2000 have varied widely from year to year, with the amount of expense incurred in the highest year (1998) being more than three times the amount of expense incurred in the lowest year (2000). (See IP Ex. 2.11) However, the highly variant nature of this expense item has not been advanced as a reason to allow no recovery. Similarly, there are standard ratemaking techniques that can be used to develop a normalized level of incentive compensation expense for ratemaking purposes; IP's alternative adjustments reflect such techniques.

In summary, the record shows that (1) incentive compensation programs are commonly included in the overall compensation programs offered by American businesses, both regulated and unregulated, with which IP competes to attract and retain qualified employees, (2) IP has had an incentive compensation program in place since at least 1991, and has made incentive compensation payments to employees for each year of this period, (3) both the Company and its customers receive significant benefits from the use of an incentive compensation program, and (4) incentive compensation payments to employees are a reasonable and necessary business expense. The objections raised by Ms. Hathhorn and Mr. Effron do not justify providing no recovery, or only a small portion of the recovery, of the test year incentive compensation expense. Incentive compensation expense is a common, reasonable and necessary cost of providing service, for which the rates established in this case should be designed to provide recovery. Allowing little or no recovery of any incentive compensation costs would be arbitrary and unsupportable.

### iii. Alternative Adjustments for Incentive Compensation Expense

In response to concerns raised by Staff witness Hathhorn that including the test year jurisdictional incentive compensation expense in the revenue requirement raises "ratepayer protection" issues, IP offered four alternative adjustments to test year incentive compensation expense. While the Company continues to believe that inclusion of the full, actual test year amount in the revenue requirement is appropriate, these alternatives would provide for a lesser amount of recovery, while still recognizing the importance of including some component in the revenue requirement for this reasonable and necessary business expense. The four alternative adjustments are summarized below.

1. <u>Five-year average (1996-2000) of jurisdictional incentive compensation expense</u>. This approach would reduce the jurisdictional expense from the test year actual amount ($5,159,000) to the five-year average amount ($2,876,000). (See IP Ex. 1.47) By normalizing the level of incentive compensation using a five-year average, there is a much smaller likelihood that the level of incentive compensation paid out by IP in a particular year will be less than the level of expense recovered from customers through rates. (IP Ex. 1.34, p. 43; see also IP Ex. 1.63, p. 31)

2. <u>Allow 50% of the test year amount of incentive compensation expense</u>. This adjustment would reduce the amount of incentive compensation expense included in jurisdictional operating expense from the actual test year amount, $5,159,000, to $2,579,000. (IP Ex. 1.48) By allowing only one-half of the actual 2000 incentive compensation expense, the Commission would create a sharing of incentive compensation costs between customers and shareholders, while still recognizing that incentive compensation is a reasonable and necessary business expense that should be reflected in setting rates. This approach would also reduce the likelihood that in a future year, IP will pay less in incentive compensation to its employees than is reflected in its rates. Further, to the extent IP meets the financial and other objectives of the incentive compensation program in a particular year and pays a larger amount of incentive compensation to its employees, shareholders will bear the additional expense. (IP Ex. 1.34, pp. 43-44; IP Ex. 1.63, pp. 31-32)

3. <u>Budgeted amount of incentive compensation for 2001</u>. This approach would reduce the jurisdictional amount of incentive compensation expense included in the revenue requirement from $5,159,000 to $4,095,000. (IP

Ex. 1.49) This approach also addresses the "ratepayer protection" issue because IP's budget assumes less than full achievement of the program's financial objectives and therefore less than the maximum payments to employees. As with alternative 2 above, if IP does better in terms of achieving the program's financial objectives, the resultant additional expense would be borne by shareholders. In addition, this approach ties the amount of cost included in the revenue requirement to the most current (2001) incentive compensation program. (IP Ex. 1.34, p. 44; IP Ex. 1.63, p. 32)

4. Provision for additional base pay in lieu of incentive compensation. IP witness Ms. Hearn estimated that if IP were to eliminate the incentive compensation program, increases of 10-15% in base pay levels would be necessary for the Company to remain competitive in the labor markets. Higher increases would be needed for those job categories that are more difficult to fill. (Rev. IP Ex. 10.1, pp. 12-13) This would translate to additional expense for base wages and associated pension and benefits costs of approximately $6.98 million, of which the jurisdictional distribution component would be $3,227,160 (IP Ex. 1.50), as compared to the actual jurisdictional test year amount of $5,159,000.

### b. Transition Employee Costs and Severance and Early Retirement Costs

During 2000, Illinois Power reduced its work force by 297 employees. Most of this work force reduction resulted from the Illinova-Dynegy merger, which closed in early 2000, and the resultant consolidation of functions at the parent company level. (Corrected IP Ex. 1.31, pp. 8-9; Corrected Rev. IP Ex. 1.28) IP made severance payments to some of the employees, and induced others to leave the Company by offering early retirement benefits.[32] In this case, IP proposed to (1) reduce test year expenses by the amount of the salaries and wages (including related pension and benefits expense and payroll taxes) paid to these employees during 2000 prior to their departure from the Company, (2) remove the actual amount of severance and early retirement

[32] Of the electric distribution portion of the total severance and early retirement costs, $15,083,000, $5,264,000 was early retirement costs, $718,000 was outplacement, medical and insurance costs, and $8,799,000 was severance pay. (IP Ex. 1.71)

expense from the distribution revenue requirement, and (3) amortize and recover the jurisdictional portion of the severance and early retirement program costs over a five-year period. (IP Ex. 1.1, p. 23; Corrected Rev. IP Ex. 1.28) The net effect of this adjustment is to reduce distribution operating expense by $14,107,000.[33] (Corrected Rev. IP Ex. 1.28; Rev. IP Ex. 3.24, p. 2, col. (20))

Staff witness Hathhorn accepted IP's adjustment to remove the expense for the payroll, pensions and benefits paid to the terminated employees in 2000, and the related payroll taxes. She opposed, however, any recovery of the severance and early retirement costs. Her reasons for disallowing any recovery of the severance and early retirement costs were (1) the Commission has disallowed recovery of this type of merger "transaction cost" in connection with recent mergers, and (2) in Docket 99-0419, IP committed not to seek recovery of any merger transaction costs from its gas utility customers; therefore, it would be inconsistent to require electric delivery services customers to pay for the jurisdictional portion of these costs. (Staff Ex. 1.0, pp. 16-18; Rev. Staff Ex. 10.0, pp. 7-11) Ms. Hathhorn's adjustment should be rejected, and the Company should be allowed to recover the severance and early retirement costs it incurred to effectuate a work force reduction and achieve the attendant savings which are being passed on to customers in this case.

Illinois Power acknowledges that, as a general matter, in the recent merger cases cited in Ms. Hathhorn's direct testimony, the Commission denied recovery of merger

[33] Removal of the payroll, pensions and benefits paid to the terminated employees and related payroll taxes reduces distribution operating expense by $2,041,000. Removal of the severance and early retirement costs further reduces distribution operating expense by $15,083,000. Adding back the annual amortization amount for the severance and early retirement costs increases distribution operating expense by $3,017,000. The net impact of these three steps is a reduction of $14,107,000. (Corrected Rev. IP Ex. 1.28)

"transaction costs", including in some of those cases employee termination costs.[34] It is not readily apparent from the orders that involved employee termination costs what the Commission's underlying rationale was for lumping employee severance costs with other costs -- such as investment banker fees, legal and accounting fees, printing and other costs for preparation of registration statements and other communications to shareholders, and similar costs that must be incurred to actually close the merger transaction – as "merger transaction costs" that should not be recovered.[35] (See IP Ex. 1.34, p. 40, and IP Ex. 1.63, p. 28) In any event, the Commission has authority to allow recovery of costs incurred in accomplishing a merger. (220 ILCS 5/7-204(c))

Here, the Company incurred severance and early retirement costs in the test year specifically to achieve a reduction in costs that is being passed on to customers in setting rates in this case. (IP Ex. 1.34, pp. 36-37, 41; IP Ex. 1.63, pp. 27-28) While Ms. Hathhorn referred to the severance and early retirement costs as costs "incurred to produce an ownership change" (Rev. Staff Ex. 10.0, p. 9), this is not accurate factually

[34] The orders cited by Ms. Hathhorn are from 1999 and 2000. In earlier cases, the Commission allowed recovery of severance costs incurred in connection with mergers. See Central Tel. Co. of Illinois, Docket 93-0252 (May 11, 1994), 1994 Ill. PUC LEXIS 206, *18-*22. Moreover, in two of the four orders cited by Ms. Hathhorn, recovery of employee severance costs does not appear to have been at issue. In Illinois-American Water Company, Citizens Utilities Company of Illinois and Citizens Lake Water Company, Docket 00-0476 (May 15, 2001), the only merger-related cost that the applicant sought to recover was the acquisition adjustment or merger premium paid to the acquired company. (Id., pp. 6, 38-39) In GTE Corporation and Bell Atlantic Corporation, Docket 98-0866 (Oct. 29, 1999), the only merger-related costs mentioned were banker and brokerage fees, legal fees, and accounting fees. (Id., p. 41)

[35] In contrast, in the Central Tel. Co. of Illinois case cited in the preceding footnote, the Commission denied recovery of "merger transaction costs", which it identified as "the one-time costs incurred to legally consummate the merger . . . included in these costs are banker fees, legal fees, accounting fees and proxy costs"; then separately discussed and allowed recovery of a portion of the applicant's employee severance costs.

(see IP Ex. 1.63, p. 28), and in any event does not seem relevant.[36] Illinois Power believes that the more appropriate analogy here is to prior orders in which the Commission allowed IP to recover the costs of an early retirement program (Dockets 89-0276 and 91-0147) and a "re-engineering" program (Docket 93-0183) that led to reductions in operating expenses.[37] (IP Ex. 1.34, pp. 37-38) More generally, IP should be allowed to recover the severance and early retirement program costs over a five-year period because these costs were incurred to achieve savings that will far exceed the costs, and that are being passed on to customers through a reduction in the distribution revenue requirement in this case.

As a result of reducing its work force by 297 employees during 2000, the Company will save both the compensation that was actually paid to these employees before they left the Company, plus the balance of their annual compensation (as well as increased salary, benefits and related costs that might have been incurred in future years as the employees received pay raises and other employee-related costs increased). The total annualized savings resulting from elimination of the 297 employees are $25,502,000 for the entire Company; the jurisdictional electric distribution portion of the savings are $14,765,000. These savings are being fully reflected in the establishment of the

[36] Ms. Hathhorn acknowledged that she had not read the Illinova-Dynegy merger agreement, and that she did not know if payment of severance and early retirement benefits to the terminated employees was a condition to the closing of the merger. (Tr. 306-07)

[37] In Docket 89-0276 (1990), the Commission allowed recovery of the costs of an enhanced retirement program IP had implemented, over a 5-year amortization period. The amortization period was extended by 46 months in Docket 91-0147 (1992). In Docket 93-0183 (1994), the Commission allowed IP to recover the costs of a re-engineering program that had been undertaken to find ways to reduce costs and increase efficiencies.

distribution revenue requirement in this case. Against these savings, IP is requesting to include $3,017,000 in the distribution revenue requirement to recover the jurisdictional portion of the severance and early retirement costs. The annual savings from the severance and early retirement program exceed the annual amortization of the costs of the program, by a factor of almost five times. (IP Ex. 1.63, pp. 27-28; IP Ex. 1.70) In light of the cost savings produced, there would seem to be no principled basis for disallowing recovery of the severance and early retirement program costs over an amortization period as proposed by IP.

Ms. Hathhorn's other argument for disallowing recovery of the severance and early retirement program costs, as noted above, was that in Docket 99-0419, in which the Commission approved the gas utility aspects of the Illinova-Dynegy merger, IP voluntarily committed not to seek recovery of the gas jurisdictional portion of any merger transaction or implementation costs. To be clear, although asked in Docket 99-0419, IP did not similarly commit not to seek recovery of any merger transaction costs from electric delivery services customers. (IP Ex. 1.34, pp. 39-40; IP Ex. 1.46) Further, as IP witness Peggy Carter explained, it is <u>not</u> "inconsistent" for the severance and early retirement program costs to be included in electric delivery services rates even though they will not be included in IP's gas utility rates:

> IP's gas rates were last set in 1994. At the time IP was seeking approval of the merger (1999), as well as currently, IP had no plans to file a gas rate case. Therefore, it is unknown when IP's gas utility customers will benefit directly from the reduction in employee levels implemented in 2000. In contrast, in 1999, IP knew it would have another DST rate case in 2001, i.e., this case, in which reduced employee levels and associated wage and salary and pension and benefits costs would be reflected in setting delivery services rates. Since electric delivery services customers will be receiving this benefit, the rates they pay should also reflect amortization and recovery

> of the severance program costs that were incurred to achieve this benefit. (IP Ex. 1.34, p. 40)

Ms. Hathhorn acknowledged that only electric delivery services customers, and not gas customers, are receiving the benefits of the cost reductions resulting from the elimination of the 297 employees. (Tr. 327-28) She also acknowledged that since IP's last gas rate case in 1994 (Docket 93-0183), the Company has incurred increased levels of plant investment and expenses that have been reflected in setting electric delivery services rates but not in setting gas rates, which continue in place at the cost levels that existed at the time of the last gas rate case. (Tr. 326-27) Given these facts and circumstances, it is by no means unreasonable for the jurisdictional electric distribution portion of the severance and early retirement program costs to be recovered through delivery services rates, even though IP voluntarily committed not to seek recovery of any merger transaction costs in its gas rates. Recovery of the severance and early retirement program costs over a five-year period as proposed by Illinois Power should be allowed.

**c. <u>Amortization of Expenses for Statutory Rulemakings</u>**

In the 1999 DST Case, the Commission allowed IP to recover costs for outside services incurred in connection with two rulemaking proceedings before the Commission that were required by the Electric Service Customer Choice and Rate Relief Law of 1997. These proceedings were the "affiliate transactions" rulemaking (Dockets 98-0013 & 98-0035 Cons.) and the "code of conduct/functional separation" rulemaking (Dockets 98-0147 & 98-0148 Cons.). The former was required by §16-121 of the PUA (220 ILCS 5/16-121) while the latter was required by §16-119A (220 ILCS 5/16-119A). In the 1999 DST Case, the Commission allowed IP to recover certain costs of these proceedings that had been incurred in 1998 and 1999, with the costs to be amortized and recovered over a five-year period. (See IP Ex. 1.1, pp. 19-20, and IP Exs. 1.19-1.20)

In this case, IP has included in the revenue requirement the portions of the costs of the two rulemakings allowed in the 1999 DST Case that have not yet been amortized and recovered. The Company has also included additional costs incurred in the two proceedings that were not known at the time of the 1999 DST Case. The entire amount is being amortized over a five-year period, consistent with the treatment in the 1999 DST Case. (IP Ex. 1.1, pp. 19-20; IP Ex. 1.19-1.20)

Staff witness Hathhorn accepted the recovery of the remaining portion of the expenses for the rulemaking proceedings that were allowed to be recovered in the 1999 DST Case, but she objected to recovery of the additional costs for the rulemakings that were incurred after the 1999 DST Case. (Staff Ex. 1.0, pp. 7-11) She characterized the latter costs as "out of period costs", i.e., they were incurred in 1999, and asserted that allowing recovery would create a mismatch between current period operating expenses and current period revenues. (Id., pp. 7-8) She contrasted these costs with those allowed for the rulemakings in the 1999 DST Case, which she characterized as test year costs, and therefore properly allowed for recovery. (Id., p. 9; Rev. Staff Ex. 10.0, p. 6)

Ms. Hathhorn's arguments are misplaced and do not justify disallowance of the remainder of the costs IP incurred for the two statutorily-required rulemakings. First, the expenses for these proceedings that the Commission allowed to be recovered in the 1999 DST Case were not incurred in the test year in that case, 1997; as indicated above, the two rulemaking dockets were not initiated by the Commission until 1998. The expenses for the rulemakings that were allowed in the 1999 DST Case were incurred in 1998 and

1999. (IP Ex. 1.34, p. 33; IP Ex. 1.63, p. 26) Second, the costs were non-recurring costs that IP was required to incur in connection with statutorily-required proceedings. The Commission determined in the 1999 DST Case that the Company should be allowed to recover its costs of participating in these two rulemakings. Contrary to Ms. Hathhorn's suggestion (Staff Ex. 1.0, pp. 8-9), IP is not now seeking to recover costs that were under-budgeted or unanticipated at the time of the 1999 DST Case. At the time of the 1999 DST Case, the two rulemakings were ongoing, and the Company fully anticipated incurring additional costs. However, because the remaining costs had not yet been incurred, they were not known with sufficient certainty to be included in setting rates in the 1999 DST Case. The additional costs have now been incurred and are known, so IP should be allowed to recover them, over a five-year amortization period, consistent with the determination in the 1999 DST Case that recovery of the costs of these statutorily-mandated rulemakings should be allowed. (IP Ex. 1.34, pp. 33-34; IP Ex. 1.63, p. 26)

#### d. <u>Amortization of Y2K Expenses</u>

In the 1999 DST Case, the Commission allowed IP to recover $2,025,000 of expenses for compliance with Year 2000 ("Y2K") requirements, with the costs to be amortized and recovered over a six-year period. In this case, the Company is seeking recovery of the jurisdictional portion of the unamortized balance of the Y2K expenses allowed in the 1999 DST Case, plus an additional $600,000 of Y2K expenses that were incurred in 1999 and 2000. The additional costs would also be amortized and recovered over a six-year period. (IP Ex. 1.1, p. 20; IP Ex. 1.21; IP Ex. 1.34, pp. 34-35; Rev. IP Ex. 3.24, p. 2, col. (15))

Staff witness Hathhorn objected to recovery of the additional Y2K costs incurred in 1999. Her rationale for disallowing these costs was essentially the same as her rationale for disallowing the additional costs of the statutorily-mandated rulemaking proceedings, namely, that they are "out of period" costs. (Staff Ex. 1.0, pp. 13-14) Ms. Hathhorn's proposed disallowance should be rejected, for reasons similar to those discussed above with respect to the additional costs for the two rulemakings. Specifically, the Commission in the 1999 DST Case allowed recovery of non-recurring costs incurred in order to address potential Y2K issues. The Company should now be allowed to recover those Y2K compliance costs that could not be identified at the time of the 1999 DST Case. (IP Ex. 1.34, p. 35; IP Ex. 1.63, p. 26)

**e. A&G Expenses Included in Distribution Operating Expense/Charges from Dynegy**

**i. IP's Determination of the Amount of A&G Expense in Distribution Operating Expense using the Labor Expense Allocator**

One of the steps necessary in developing the distribution operating expenses is to determine the amount of the utility's A&G expenses that should be included in distribution operating expenses. A&G expenses include the costs associated with such functions as accounting, regulatory, legal, human resources, public affairs, executive officers and administrative staff. Costs associated with office supplies and expenses, outside services, property insurance and claims, pensions and benefits, and miscellaneous expenses are also recorded as A&G expenses. (IP Ex. 1.34, p. 47) Under the USOA, A&G expenses are recorded in Accounts 920 through 935. (Tr. 290; see IP Ex. 1.51 for a listing of these accounts.) Like G&I plant, A&G expenses support all of a utility's businesses; it is in the nature of these joint and common costs that they are needed to support a single line of business, but can also support additional lines of business without significant increase.[38] (IP Ex. 1.34, p. 5) Like G&I plant, the USOA does not require that a utility maintain its books of account or financial reports in a manner that allocates or assigns its A&G expenses among the utility's various business functions. (Tr. 755-57) Therefore, for regulatory purposes in setting rates for one of the utility's several lines of business, it is necessary in some manner to allocate or assign a portion of the A&G expenses to the service for which the rates are being set.

In this case, Illinois Power determined the amount of its A&G expenses to be included in distribution operating expenses in a similar manner to the way it determined the amount of G&I plant to be included in rate base, using labor expense allocation factors as the Commission had directed in the 1999 DST Case. (IP Ex. 1.1, pp. 16-17; IP Ex. 1.4; IP Ex. 1.34, pp. 5, 55-56) IP started with total electric A&G expense as reported in its FERC Form 1 for 2000, and allocated a portion of the total electric A&G expense to electric distribution using a transmission and distribution labor expense allocator. No party noted any errors in IP's calculation of the labor expense allocation factors. (IP Ex. 1.1, pp. 16-17; IP Ex. 1.34, pp. 55-56; IP Ex. 1.63, pp. 7-8)

#### ii. Staff Witness Lazare's, IIEC Witness Phillips' and CUB/AG Witness Effron's Adjustments are Without Merit

Staff witness Lazare and IIEC witness Phillips each took issue with the amount of A&G expense that IP included in distribution operating expense using the labor allocation procedure. They both contended that IP's use of the labor allocator produced a large increase in the amount of A&G expense included in distribution operating expense

[38] As stated in the NARUC Electric Utility Cost Allocation Manual (p. 15), "Common costs are incurred when an entity produces several services using the same facilities or inputs." (Tr. 753)

as compared to the amount of A&G expense included in distribution operating expense in the 1999 DST Order. As with their objections to the amount of G&I plant in distribution rate base, discussed in Section II.B.3.c.ii above, at the root of Mr. Lazare's and Mr. Phillips' objections is the fact that in the fourth quarter of 1999, IP sold its fossil generating stations to DMG and sold its nuclear generating station to AmerGen, with IP's fossil generation employees and nuclear generation employees becoming employees of DMG and AmerGen, respectively. As a result, whereas during the 1997 test year used in the 1999 DST Case the Company owned generating stations, had a generation business function and had generation employees whose labor expense was included in the denominator of the labor expense allocation factor, in the 2000 test year used in this case, IP owned essentially no generation, had essentially no generation labor expense, and therefore did not include any generation labor expense in the development of its labor expense allocation ratios for A&G expense. (Staff Ex. 5.0, pp. 5-6; IIEC Ex. 3, pp. 4-8; see IP Ex. 1.34, pp. 55-56)

Rather than accepting the amount of A&G expense to be included in distribution operating expense as determined by the Company using the labor expense allocator, Mr. Lazare proposed that IP be allowed an amount of A&G expense in distribution operating expense equal to the amount of A&G expense allowed in operating expense in the 1999 DST Case, plus a percentage increase equal to the percent increase in direct O&M expense allowed in this case over the amount of direct O&M allowed in the 1999 DST Case. (Staff Ex. 5.0, pp. 15-16; see Staff Ex. 21.0) Mr. Phillips proposed that A&G expense be included in distribution operating expense by applying the same ratio between

A&G expense and O&M expense as resulted from the Commission's determinations in the 1999 DST Case. (IIEC Ex. 3, p. 8)

Mr. Lazare's and Mr. Phillips' proposed limitations on the amount of A&G expenses to be included in distribution operating expense in this case are arbitrary and should be rejected, just like their proposed limitations on the amount of G&I plant in distribution rate base should be rejected. (See Section II.C.3.c above) Illinois Power properly determined the amount of its A&G expense that should be included in distribution operating expense using a labor expense allocator as prescribed by the Commission in the 1999 DST Case. Mr. Lazare's and Mr. Phillips' proposed adjustments were not based on any sort of detailed review of IP's overall A&G expenses or on identification of any A&G expenses that were imprudently incurred or are unnecessary to provide service. Indeed, Mr. Lazare not only failed to perform or review any studies or analyses of IP's test year A&G expenses to identify any specific items of A&G expense that should not be included in the revenue requirement (Tr. 780), he did not even perform or review any studies or analyses to identify the types or categories of A&G expenses that IP incurred in the test year.[39] (Tr. 780-81)

Rather, like their proposed adjustments to G&I plant, Mr. Lazare's and Mr. Phillips' adjustments to A&G expense are grounded in an erroneous premise that the

[39] In contrast, Staff witnesses Dianna Hathhorn and Bonita Pearce of the Commission's Accounting Department conducted a thorough review of the operating income statement proposed by the Company, and proposed numerous specific adjustments to IP's proposed operating expenses, including specific disallowances and other adjustments to A&G expenses. (Tr. 283-86, 288-89) As discussed in other sections of this brief, IP has accepted some of Ms. Hathhorn's and Ms. Pearce's adjustments and is continuing to dispute others; however, for purposes of this section, the point is that the Accounting Department representatives assigned to this case conducted a substantive review of IP's A&G expenses, while Mr. Lazare did not.

Commission, in the 1999 DST Case, determined a fixed and immutable relationship between the amount of direct O&M expense and the amount of A&G expense needed to provide distribution service, which should be carried forward in all future cases. (IP Ex. 1.63, pp. 8-9) There is no basis for such a premise, or for the arbitrary limitations Messrs. Lazare and Phillips would impose on the amount of IP's A&G expense to be included in distribution operating expense. The discussion in Section II.B.3.c.ii of this Brief about the conceptual flaws in Mr. Lazare's and Mr. Phillips' proposed adjustments to G&I plant is equally applicable to their proposed adjustments to A&G expense.[40]

Mr. Effron proposed a different, but similarly unsupported, adjustment to the A&G expenses included in distribution operating expenses. Mr. Effron focused solely on the increase in one A&G account, Account 923, Outside Services Employed, from 1997 (the test year in the 1999 DST Case) to 2000. Within that account, he focused solely on the charges to IP for services provided in 2000 by its corporate parent, Dynegy (charges which, of course, did not exist in 1997). Without giving any consideration to decreases in other accounts that IP has been able to achieve as a result of functions that IP formerly

[40] As he did with respect to his proposed adjustment to G&I plant, Mr. Lazare attempted to support his proposed adjustment to A&G expense, by relying on certain statements by IP witness Alec Dreyer in Docket 99-0209 (in which IP's sale of its fossil generation to DMG was approved) and on a faulty comparison to allocations made by the Ameren companies in their current DST case, Docket 00-0802. In Sections II.B.3.c.ii and iii of this Brief, IP showed that these prongs of Mr. Lazare's argument were faulty. Among other things, IP explained in Section II.B.3.c.ii that DMG ceased to rely on IP for the provision of significant levels of overhead, administrative and support services after the closing of the Illinova-Dynegy merger because it thereafter obtained those services from its corporate parent, Dynegy. IP also explained in Section II.B.3.c.ii that in 2000, IP properly billed both DMG and AmerGen (the buyer of IP's nuclear generating station) for those services that IP provided to each company, and that the revenues from and costs of providing these services were accounted for in a manner that removes the revenues and costs from the determination of the revenue requirement in this case, facts that Mr. Lazare did not dispute. (See IP Ex.1.34, pp. 56-61, and IP Exs. 1.56-1.57; Tr. 768-777)

performed internally being transferred to Dynegy after the merger, Mr. Effron recommended that all charges from Dynegy be disallowed. (GCI Ex. 2.0, pp. 11-14) As detailed in Section II.C.3.e.iii of this Brief, below, IP responded with a detailed itemization and explanation of the services provided by Dynegy and the related charges, and also identified reductions in internal costs that it had achieved as a result of the transfer of functions to Dynegy. In his rebuttal, Mr. Effron, without responding to the specifics of IP's presentation, simply continued to recommend that all charges from Dynegy be disallowed. (GCI Ex. 4.0, p. 10) His proposed adjustment is arbitrary and not based on any specifics of the A&G costs in question, and should be rejected.[41]

#### iii. IP's Electric A&G Expenses are Reasonable

In response to Mr. Lazare's and Mr. Phillips' proposals, the Company presented an analysis of the change in its electric A&G expenses from 1997, the test year in the 1999 DST Case, to 2000, the test year in this case. The total annual unadjusted electric A&G expenses (i.e., including any non-recurring expenses and before consideration of any ratemaking adjustments), decreased approximately 3% from 1997 to 2000, from \$73.6 million to \$71.6 million. In fact, total electric A&G expenses had increased by 17.9% from 1997 to 1999, but then decreased by 17.4% from 1999 (the year in which IP's generation assets were sold) to 2000. (IP Ex. 1.34, p. 48; IP Ex. 1.51)

From 1997 to 2000, there were three A&G accounts that showed increases: Account 920, Administrative and General Salaries (\$5.3 million increase); Account 923,

[41] In contrast to Mr. Effron, Staff witness Ms. Hathhorn did review the Dynegy billings to IP for the test year, and in fact identified an error, which the Company has accepted as an adjustment in this case. (See "Correction to billings from Dynegy under the SFA" in Section II.C.2. of this Brief) Her adjustment reduced jurisdictional operating expense by \$1,035,000. (Rev. IP Ex. 3.24, p. 3, col. (30)) Ms. Hathhorn did not identify any other errors in the Dynegy billings to IP. (Tr. 289)

Outside Services ($25.2 million increase); and Account 925, Injuries and Damages ($7.1 million increase). (IP Ex. 1.34, p. 48) However, the 2000 total in Account 920 included $13 million of one-time severance payments. IP has proposed to remove the severance payments from test year expenses and amortize them over five years (see Section II.C.3.b above). Excluding the $13 million of severance costs recorded in 2000, A&G salaries fell by about $7.7 million, or 38%, from 1997 to 2000. Further, the 2000 total in Account 920 does not fully reflect the impacts of IP's headcount reductions in 2000, because it includes compensation paid to terminated employees in 2000 before their departure from the Company. IP has also proposed to remove these amounts from test year expenses for ratemaking purposes (see Section II.C.3.b). (IP Ex. 1.34, p. 49)

Overall, IP reduced its headcount in A&G positions by 155 employees from year-end 1997 to year-end 2000, from 443 employees to 288 employees. In fact, the number of A&G employees had increased to 461 at year-end 1999, so the decrease in A&G headcount in 2000 was actually 173 employees.[42] (IP Ex. 1.34, p. 50; IP Ex. 1.52) Overall, the Company's annualized savings due to the elimination of 297 employees in 2000 is $25,501,515, of which $14,765,377 is the jurisdictional electric distribution portion. (IP Ex. 1.63, p. 27; IP Ex. 1.70)

The $7.1 million increase in expenses recorded in Account 925, Injuries and Damages, from 1997 to 2000 was primarily due to the recording of a $5.5 million accrual in 2000 for three pending litigation claims against IP. The Company has proposed to

[42] In addition, the headcount in the T&D functions was reduced from 1,880 employees at year-end 1997 to 1,749 employees at year-end 2000, and in fact was reduced by 196 employees (from 1,945 at year-end 1999 to 1,749 at year-end 2000) during 2000. (IP Ex. 1.34, p. 50; IP Ex. 1.52)

remove this $5.5 million accrual from test year expenses and amortize it over three years (see Section II.C.3.f below). (IP Ex. 1.34, p. 54)

The $25.2 million increase in Account 923 from 1997 to 2000 is primarily attributable to the billings to IP associated with services now provided by Dynegy. This increase also includes an expense for a portion of bonuses paid to Dynegy executives that was allocated to IP; the Company has removed this expense in its entirety for ratemaking purposes. (IP Ex. 1.30; see Section II.C.2 above) Excluding the expense for these bonuses, the 2000 expense for Account 923, Outside Services Employed, was approximately $16.3 million higher in 2000 than in 1997. (IP Ex. 1.34, p. 52)

Ms. Carter also detailed the nature of the billings from Dynegy included in Account 923 for 2000, the nature of the services provided by Dynegy, and the reductions in IP's work force that have been made possible by the transfer of functions to Dynegy. (IP Ex. 1.34, pp. 50-53; IP Exs. 1.52-1.55) Services provided by Dynegy fall into seven principal areas: (1) President/CEO/COO; (2) financial; (3) legal; (4) human resources; (5) information technology ("IT"); (6) communications; and (7) administration. The functions performed by Dynegy in these seven areas are detailed on IP Exhibit 1.55, pp. 1-4, and include serving as IP's Chairman, Chief Executive Officer, Chief Financial Officer, Treasurer, Assistant Treasurer and Vice President - Tax; managing IP's commercial paper program, debt financings and relationships with rating agencies, banks and the financial community; preparation of IP's federal and State tax filings and estimated and final tax payments; review of IP's SEC filings and financial statements and legal support for SEC filings; overseeing the insurance and risk management functions, negotiation of IP's insurance premiums and maintenance of relationships with insurance carriers; performance of internal audits for IP; performance of the corporate secretary function, including maintenance of corporate records; leadership and direction for human resources programs and functions; and leadership and direction for IT functions, including monitoring infrastructure and monitoring and maintaining electronic storage, server support, applications development, IT contract administration, and development and maintenance of specific IT functions.[43]

In a number of the functional areas in which services are now provided to IP by Dynegy, IP has been able to achieve significant headcount reductions. For example:

- Dynegy now provides the internal audit function for IP; therefore, IP's Audit and Compliance Services group (12 employees in 1997) was eliminated in 2000.

- IP's shareholder services function was eliminated from its Legal Services Department; the head count in Legal Services dropped from 24 in 1997 to 12 in 2000.

- IP's Human Resources group has been reduced from 53 persons in 1997 to 25 persons in 2000.

- With many of IP's accounting, financial planning and management and treasury functions now performed by Dynegy, IP's Financial Business Group has been reduced from 80 persons in 1997 to 36 persons in 2000.

- With IT functions now being directed by Dynegy, IP's head count in IT has dropped by 46 employees from 1997 to 2000. (IP Ex. 1.34, pp. 50-51; IP Ex. 1.52)

The costs for the services and functions performed by Dynegy are billed to IP in accordance with the SFA approved by the Commission in Docket 99-0114. (IP Ex. 1.34,

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[43] The listing of services and functions in this paragraph is taken from IP Exhibit 1.55, which was originally designated as confidential in its entirety. IP has determined that the listing of services and functions on IP Ex. 1.55 does not need to be maintained as confidential; however, the dollar amounts shown on IP Ex. 1.55 should continue to be treated as confidential.

p. 53) As noted earlier in this brief, Staff witness Dianna Hathhorn reviewed the test year billings from Dynegy to IP and found one error, which IP has accepted as an adjustment. (See Section III.C.2 above) No other witness identified any errors or non-compliances in Dynegy's billings for services pursuant to the SFA.[44]

When adjustments are made for non-recurring costs and other ratemaking adjustments, the data show that IP achieved significant reductions in its ongoing level of electric A&G expenses from 1997 to 2000. The total electric A&G expenses in 1997 were $73.6 million; there were no significant non-recurring expenses that were removed from this test year amount for ratemaking purposes in the 1997 DST Case. The total electric A&G expenses in 2000 were $71.6 million; however, IP has removed a total of $37.2 million of non-recurring expenses or one-time adjustments from this total for ratemaking purposes, resulting in an ongoing level of electric A&G expenses of $34.5 million – a 53.2% reduction from 1997. (IP Ex. 1.63, p. 35; IP Ex. 1.72)

#### iv. IP Has Not Failed to Pass Merger Savings on to Delivery Services Customers

In connection with his proposed limitation on the amount of A&G expense in distribution operating expense, Staff witness Lazare contended that IP had not realized cost savings anticipated at the time of the announcement of the Dynegy-Illinova merger, or at least was not reflecting the savings in its delivery services revenue requirement. (Staff Ex. 5.0, pp. 13-15; Staff Ex. 14.0, p. 15) Mr. Lazare's contention is baseless.

Mr. Lazare cited statements made at the time of the merger announcement that the combined companies expected annual pre-tax revenue enhancements and cost savings of

[44] Mr. Lazare specifically acknowledged that he was not contending that IP had not been billed correctly for services provided by Dynegy under the SFA. (Tr. 770-71)

$125 million to $165 million, with about one-third of this amount attributable to anticipated cost savings. (Staff Ex. 5.0, pp. 13-14) He acknowledged that contemporaneous statements put the anticipated cost savings at $59 million. He also acknowledged that the figures for anticipated revenue enhancements and cost savings were anticipated results for the entire, combined post-merger organization, not just for Illinois Power. (Tr. 777-78) Assuming these savings were achieved, only a portion would be attributable or allocable to IP's electric distribution business. (IP Ex. 1.34, pp. 53-54)

In any event, the record in this case shows:

- IP eliminated 297 employees in 2000, almost entirely as a result of the merger, resulting in annualized savings to the Company of $25.5 million and to the electric distribution business of $14.8 million.[45] (IP Ex. 1.63, p. 27; IP Ex. 1.70)

- IP's total electric A&G expenses fell by $15.1 million from 1999 to 2000. (IP Ex. 1.34, p. 54; IP Ex. 1.51)

- IP's total headcount in transmission, distribution and A&G functions was reduced by 369 employees from year-end 1999 to year-end 2000.[46] (IP Ex. 1.34, p. 54; IP Ex. 1.52)

In short, IP has both realized merger-related cost savings and is reflecting those savings in its proposed revenue requirement in this case.

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[45] IP finds it ironic that while Staff witness Lazare contends that IP has reflected no merger-related savings in the distribution revenue requirement, Staff witness Hathhorn seeks to disallow the severance payments to the 297 employees whose termination produced the above savings because the employee reductions resulted from the merger. (See Section II.C.3.b above)

[46] In Docket 99-0419, in which the Commission approved the gas utility aspects of the merger, IP indicated an anticipated 5% reduction in the combined 6,500 person workforce of Illinova and Dynegy, i.e., a 325 employee reduction. In fact, Illinois Power's headcount alone was reduced by 369 from year-end 1999 to year-end 2000. (IP Ex. 1.34, p. 54)

In summary, the adjustments to A&G expenses proposed by Messrs. Lazare, Phillips and Effron should be rejected. They ignore the nature of common costs, and are based on an invalid assumption that the Commission has established a fixed and immutable relationship between direct O&M expense and A&G expense in the distribution revenue requirement that must be adhered to. The Company's total electric A&G expenses have actually decreased since 1997, the test year in the 1999 DST Case, and since 1999, when IP divested its generation assets and business and the Illinova-Dynegy merger was announced. These witnesses' adjustments are not based on any analysis of the specific A&G expenses incurred by the Company in 2000 or on any identification of specific A&G expense items that are imprudent or unnecessary. These witnesses have not refuted IP's detailed explanation of its test year A&G expenses, including the billings for services and functions now performed by Dynegy. The A&G expenses that the Company has included in the distribution revenue requirement are reasonable and necessary to support the distribution business, and should be allowed for ratemaking purposes.

**f. <u>Amortization of Accrual for Injuries and Damages</u>**

During the test year, IP recorded a $5.5 million accrual for liability exposure for injuries and damages expense in connection with three pending or potential litigation claims. (IP Ex. 1.34, p. 66) Creation of this accrual was consistent with Statement of Financial Accounting Standards No. 5, Accounting for Contingencies ("SFAS 5"). SFAS 5 states that an estimated loss for a loss contingency should be charged to expense, and a liability recorded, if both of the following conditions are met: (1) information available prior to the issuance of the financial statements indicates that it is probable that a liability has been incurred at the date of the financial statements, and (2) the amount of the loss can be reasonably estimated. IP recognized an expense for these three claims in December 2000 because it was probable that a liability had been incurred and IP could reasonably estimate the loss. (Id.; IP Ex. 1.63, p. 40)

Initially, IP proposed to include the jurisdictional portion of the $5.5 million amount in test year expenses as a legitimate and necessary operating expense. However, in response to questions raised by CUB/AG witness Effron about the resulting test year level of Injuries and Damages expense in relation to the levels incurred in recent years (see GCI Ex. 2.0, pp. 8-10), the Company proposed to amortize the $5.5 million accrual over a three-year period. The three-year amortization period is based on two factors: (1) The DST rates established in this case are expected to be in effect for approximately three years (early 2002 until early 2005); therefore, the expense would be fully amortized by the time new DST rates are established; and (2) litigation matters such as those for which the accrual was established can take two to five years to be brought to resolution. (IP Ex. 1.34, p. 67) Removing the accrual expense from test year expenses and amortizing the amount over a three-year period, as IP proposes, results in a net reduction to operating expenses of $3,225,000. (Id.; IP Ex. 1.60)

Although the Company is now proposing a three-year amortization of the claims accrual, Mr. Effron continues to object to any recovery of this expense in test year operating expense, on the grounds that IP should not be allowed to include both actual claims paid, and accruals for future claims payments, in the test year. (GCI Ex. 4.0, pp. 11-12) Mr. Effron's position ignores the relevant accounting requirements, and should be rejected. His argument that IP should not be allowed to include both actual claims paid and accruals for future payments is a red herring, because both the current period payments <u>and</u> the accrual are current period <u>expenses</u>. As summarized above, SFAS 5 <u>requires</u> the recording of a current period expense when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Mr. Effron essentially agreed that the recording of an expense is required by Generally Accepted Accounting Principles under such circumstances, and he did not take issue with the Company's determination that this particular expense and accrual should be recorded in 2000. (See Tr. 414-19) Since the $5.5 million accrual is a current period (test year) expense, it is appropriately recognized in setting rates.

Mr. Effron correctly observed that recording the expense for the $5.5 million accrual resulted in an unusually high total level of Injuries and Damages expense in 2000 as compared to prior years. The Company appropriately addressed this fact by agreeing to amortize the $5.5 million accrual over three years. (IP Ex. 1.63, p. 40) However, Mr. Effron's proposal to completely exclude the $5.5 million accrual from the revenue requirement in this proceeding is unsupported and must be rejected.

#### g. <u>Amortization Expense for Intangible Plant</u>

CUB/AG witness Effron proposed a reduction in amortization expense for intangible plant, on the grounds that the current annual amortization rate would result in the unamortized balance of intangible plant in service at December 31, 2000, being fully amortized by about June 2003. (GCI Ex. 2.0, p. 16) His proposal must be rejected for at least two reasons. First, IP is continuing to add intangible plant. Indeed, in this case, IP is proposing intangible plant capital additions to distribution rate base totaling $7,235,000 (as contrasted to a net amount of intangible plant in service at December 31, 2000 of approximately $13.8 million). (See Rev. IP Ex. 3.24, p. 1, cols. (2), (3), (4) and (7)) Therefore, IP does not expect to reach a fully amortized level of intangible plant in the foreseeable future. (IP Ex. 1.34, p. 70) Second, as Staff witness Mary Everson pointed out, the appropriate amortization rate should be determined based on the useful life of the asset being amortized, not on the frequency of the utility's rate case filings. (Staff Ex. 11.0, p. 4) Mr. Effron has made no showing that the Company's amortization rate is inappropriate based on the useful lives of its intangible plant assets.

### h. Contributions to Community Organizations

Staff witness Pearce proposes a disallowance for contributions made by the Company during 2000 to a number of community organizations that engage in economic development activities in communities throughout IP's service area.[47] She characterized these expenditures as promotional or good will in nature and contended that IP should not be allowed to include them in the revenue requirement because the Company received a "benefit" from these contributions. (Staff Ex. 3.0, pp. 3-5; Staff Ex. 12.0, pp. 2-4) Illinois Power submits that the Commission should allow inclusion of these expenditures for ratemaking purposes, as a reasonable and appropriate business expense. As IP witness Peggy Carter explained:

> The activities of these organizations benefit the community as a whole and IP's customers . . . Many of these organizations are focused on improving the local educational systems and providing for those families in their areas that are in need. Other organizations are focused on attracting new businesses to their areas, improving the level and education of the work force, and providing assistance to businesses that have specialized needs. The efforts of these types of organizations assist customers in IP's service territory to maintain jobs or stay in business. Without this assistance, IP could likely have increased uncollectibles and decreasing sales. Therefore,

[47] There is one exception to the statement that these community organizations engage in economic development activities. Specifically, one of the contributions at issue was to an organization supporting a referendum to approve a higher property tax rate for the Decatur public schools (Tr. 269), and thereby make available more funding for public schools in Decatur.

> IP's payments to these community organizations are a sound and prudent expense that directly benefits customers. (IP Ex. 1.34, pp. 46-47)

As Ms. Carter explained, contrary to Ms. Pearce's characterization, IP does not participate in these organizations for "promotional benefit". Rather, IP belongs to, participates in, and otherwise actively supports those organizations that are geared towards the enhancement, growth and advancement of IP's service territory – IP's participation in the activities of these organizations is beneficial to the customers in its service area. (IP Ex. 1.63, p. 42)

As noted above, Ms. Pearce contended that contributions to these organizations should be disallowed because IP receives a "benefit" from them. This rationale, however, provides no basis for disallowing costs. As Ms. Pearce acknowledged, IP receives "benefits" from most if not all payments it makes, such as payments of wages and salaries to its employees, and payments to suppliers for materials and equipment. (Tr. 272) Further, Ms. Pearce acknowledged that reduced uncollectibles in the test year would be reflected in establishing the revenue requirement, and that higher sales would result in lower per-unit charges to customers to recover the revenue requirement as determined by the Commission. (Tr. 273) The Commission should reject Ms. Pearce's proposed disallowance of these contributions.

### D. Cost of Capital

Evidence concerning the cost of capital and rate of return was filed by three parties in this docket, namely, Illinois Power, Staff and IIEC. In its initial filing, Illinois Power requested an overall rate of return on rate base of 9.22%, including a 12.50% rate of return on common equity. (IP Ex. 3.2) During the course of these proceedings, however, IP, Staff and IIEC reached agreement on the rate of return, including the components thereof, that should be adopted for purposes of setting rates in this proceeding. The agreed rate of return is 8.69%. No other party raised any objection to the agreed rate of return. The agreed rate of return, including the components thereof, were presented by Staff's cost of capital witness, Rochelle Langfeldt, in Staff Exhibit 20.0, and are as follows:

| Description | Amount | Capital Structure Ratio | Cost Rate | Weighted Rate |
|---|---|---|---|---|
| Long-Term Debt | $1,095,159,675 | 34.40% | 7.01% | 2.41% |
| Trans.Fndg. Instr. | 592,048,011 | 18.60% | 7.01% | 1.30% |
| Short-Term Debt | 170,032,566 | 5.34% | 3.98% | 0.21% |
| Preferred Stock | 45,430,145 | 1.43% | 5.05% | 0.07% |
| Preferred Securities | 94,297,622 | 2.96% | 8.63% | 0.26% |
| Common Equity | 1,186,423,425 | 37.27% | 11.89% | 4.43% |
| Total | $3,183,391,444 | 100.00% | | 8.69% |

As Ms. Langfeldt explained, the 11.89% rate of return on common equity that was used in arriving at the overall rate of return of 8.69% is Staff's recommended rate of return on common equity, which she supported in her prepared testimony and exhibits (Staff Exs. 4.0 and 13.0) that were admitted into evidence. As she also explained, the other components of the capital structure were determined using a measurement date of August 31, 2001. (Tr. 574-75)

The Commission should adopt the overall rate of return of 8.69%, including the capital structure components and cost rate shown on Staff Exhibit 20.0, as fair and reasonable for purposes of this proceeding.

## III. COST OF SERVICE AND RATE DESIGN

### A. Cost of Service Studies

#### 1. Overview of Embedded Cost of Service Studies

In its direct case filing, Illinois Power submitted an embedded cost of service study ("ECOSS") for the distribution revenue requirement that determined cost responsibility by customer class.[48] The Company also submitted a study calculating the revenue requirement and class cost responsibility for meters subject to unbundling. (IP Ex. 8.1, pp. 2-4, 8-9; IP Exs. 8.2, 8.8-8.9) A revised ECOSS and revised unbundled meter revenue requirement and cost of service study were submitted as part of IP's rebuttal filing, reflecting various corrections and changes, modifications in response to certain recommendations by other parties, and changes in the level of detail presented. (IP Ex. 8.10, pp. 2-3, 9-10; IP Exs. 8.11, 8.14-8.15) In general, the Company's ECOSS was prepared consistently with the methodologies used in the 1999 DST Case. (See Staff Ex. 5.0, p. 20) The revenue requirement for meters subject to unbundling was determined using the same methodologies approved by the Commission in Docket 99-0013, the meter unbundling case. (IP Ex. 8.1, p. 8; IP Ex. 8.10, p. 9) The ECOSS results and unbundled meter revenue requirement that IP believes should be used for purposes of this case are shown in the following exhibits: (1) ECOSS for the distribution business – IP Exhibit 8.11; (2) revenue requirement for meters subject to unbundling – IP Exhibit 8.14; and (3) ECOSS for the meter revenue requirement – IP Exhibit 8.15.

Witnesses for Staff, IIEC and CUB/AG criticized several specific aspects of the Company's cost of service studies and of their use in setting specific rates and charges in

[48] The four major customer classes used in IP's ECOSS are Residential, Small Use General Service, Demand-Metered General Service, and Lighting. (See IP Ex. 8.2)

this case. These issues are discussed in Sections III.A.2 and III.C below. In general, however, its appears that the cost of service witnesses for the other parties have accepted IP's ECOSS for use in this case, subject to certain specific modifications that each may have proposed. (Staff Ex. 5.0, p. 20 and Tr. 724-26 (Lazare, Staff); IIEC Ex. 6, p. 13 (Phillips, IIEC); GCI Ex. 3, p. 7 (Smith, CUB/AG)) No party presented a separate cost of service study.

### 2. Cost of Service Study Issues

This section addresses specific issues that arose during this proceeding in connection with IP's ECOSS for the distribution business and its ECOSS for the meter revenue requirement.

#### a. Allocation of Miscellaneous Revenues to the Customer Classes

CUB/AG witness Smith took issue with the allocation of miscellaneous revenues to the customer classes in IP's ECOSS. (Miscellaneous revenues received from customers serve to reduce the net revenue requirement that must be recovered through the base charges for distribution service.) Ms. Smith's position was that miscellaneous revenues should be allocated to the customer classes on the same basis as the costs incurred to produce those revenues (except for those miscellaneous revenues that do not have underlying costs). Using IP's ECOSS, she reallocated most of the miscellaneous revenues to the customer classes on the same basis as Distribution Labor Operating Expense. (GCI Ex. 1, pp. 7-9; GCI Ex. 3, pp. 2-3; Tr. 898-99)

Ms. Smith's reallocation of miscellaneous revenues is not appropriate. IP Exhibit 8.12 shows the Company's allocation of miscellaneous revenues, by type, to the rate classes. As the exhibit shows, the largest categories of miscellaneous revenues are forfeited discounts, equipment rentals, and service activation fees – these three categories account for about $7.9 million of the $9.4 million of test year miscellaneous revenues. Forfeited discounts (i.e., late payment charges) and service activation fees were allocated directly to the customer classes to which the forfeited discounts and service activation fees were billed, resulting in 66% of the total forfeited discounts and 95% of the service activation fee revenue being allocated to the residential class. (IP Ex. 8.10, p. 6) Equipment rental revenues were allocated to the non-residential customer classes because these rental revenues come from large customers renting transformers, customer substations and customer metering equipment. No equipment rental revenue was allocated to the residential class because residential customers do not need to rent this type of equipment. (Id.)

Ms. Smith contended that a portion of equipment rental revenues should be allocated to the residential class because the costs of transformers and substations that IP rents to customers are recorded in accounts that are allocated to the residential class. (GCI Ex. 1, pp. 7-8) This is incomplete reasoning. The costs of the plant investment and related expenses are allocated to the customer classes, including residential, on the basis of their respective cost of service responsibilities. (Tr. 516) This produces a fair allocation of the underlying costs, which Ms. Smith did not challenge. However, the non-residential classes (in particular the demand-metered classes) make a contribution to recovery of their allocated share of these costs through the payment of rental revenues. (Tr. 517) Residential customers do not rent this equipment, and therefore the residential class does not make any contribution to its allocated share of these costs through the payment of rental revenues. (Tr. 516-17) Thus, IP has appropriately allocated the equipment rental revenues to the customer classes that pay the rents (i.e., non-residential), since these rental payments reduce the amount of these classes' revenue requirement responsibility that must be recovered through the base distribution rates. Accordingly, Ms. Smith's re-allocation of miscellaneous revenues should be rejected.

**b. Use of Replacement Costs to Allocate Costs of Meters and Service Drops to the Customer Classes**

In the distribution ECOSS, IP used the replacement (i.e., current) costs of the meters and services that serve each customer class as the basis for allocating the embedded costs of meters and service drops to the customer classes. IIEC witness Phillips criticized this allocation methodology as inconsistent with the concept of an embedded cost of service study. (IIEC Ex. 3, p. 11) However, the Company's allocation methodology for meter and service drop costs was well-founded and appropriate.

The same type of meter is not used to serve all customer classes. Rather, meters used to serve larger, demand-metered non-residential customers are more complex, and therefore more costly, than the meters used to serve residential and small use general service customers. (IP Ex. 8.16, pp. 2-3; Tr. 517-19) As the NARUC Electric Utility Cost Allocation Manual recognizes (p. 98), "The metering account is a clear example of an account requiring weightings for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer." (Tr. 518) However, IP's meters and services are mass-accounted in Accounts 370 and 369; therefore, it is not possible to identify from IP's accounting records the embedded costs of the types of meters used to serve residential customers and the embedded costs of the more complex meters used to serve demand-metered customers. (IP Ex. 8.16, pp. 2-3)

IP therefore used current replacement costs for the types of meters and services used to serve each customer class in allocating the investment in Accounts 369 and 370 to the customer classes. Specifically, (1) the replacement costs to serve each class of customers were multiplied by the number of customers in each rate class; (2) these products were then summed; (3) the replacement costs for each rate class were divided by the total replacement costs (item (1) divided by item (2)) to derive a percentage of the total for each class; and (4) the percentage for each class was then multiplied by the embedded costs in the meters and services asset accounts to allocate the embedded costs to the rate classes. (IP Ex. 8.10, p. 4) As noted above, this approach is supported by the NARUC Electric Utility Cost Allocation Manual. (See IP Ex. 8.16, p.3) It is also consistent with the method of allocating meters and services to the rate classes that was used in IP's 1999 DST Case. (IP Ex. 8.10, p. 4)

#### c. G&I Plant and A&G Expenses included in Revenue Requirement for Meters Subject to Unbundling

IIEC witness Phillips questioned what he perceived to be a large amount of G&I plant and A&G expense in IP's revenue requirement for meters subject to unbundling, in relation to the direct meter investment and expenses in the meter revenue requirement. He recommended that the Commission not use IP's meter ECOSS to set metering rates, although he offered no alternative study. (IIEC Ex. 3, pp. 14-16; IIEC Ex. 6, pp. 10-11) However, IP's cost of service witness, Karen Althoff, explained that G&I plant and A&G expense were allocated to the metering function on the same basis as approved by the Commission in Docket 99-0013, namely, based on the relationship of meter service labor to total electric distribution labor. Meter service labor was 18.08% of total electric distribution labor; this percentage was applied to electric distribution G&I plant and

A&G expenses to determine the amounts of G&I plant and A&G expenses to be allocated to the metering function. (IP Ex. 8.10, pp. 9-10; IP Ex. 8.16, pp. 7-8) IIEC witness Phillips did not provide any alternative approach and did not dispute the fact that the allocation of G&I plant and A&G expenses was made in the same manner as approved in Docket 99-0013.

### B. Allocation of the Distribution Revenue Requirement to the Customer Classes

Illinois Power proposes that the distribution revenue requirement be allocated among the delivery services customer classes on the basis of the embedded cost of service study results, with no deviations from cost of service based on other considerations. (IP Ex. 6.6, p. 2) Staff witness Lazare also testified that the revenue requirement should be allocated solely based on cost of service. (Staff Ex. 5.0, pp. 20-23; Tr. 726) No other witness proposed any deviations from cost of service as the basis for allocating the distribution revenue requirement to the customer classes.

### C. Delivery Services Tariff Rate Design

#### 1. Residential DST Rate Design

##### a. Facilities Charges

Illinois Power, Staff and CUB/AG are in agreement that the residential DST facilities charges should be set equal to the current facilities charges in the bundled rates, adjusted for the 5% statutorily-mandated residential rate decrease scheduled for May 1, 2002. (IP Ex. 6.6, pp. 6-7; Staff Ex. 14.0, p. 18; GCI Ex. 3, pp. 3-4; Tr. 727, 900-01) In other words, the residential DST facilities charges should be set equal to the facilities charges that will be in effect beginning May 1, 2002. This approach will promote rate continuity as residential customers become eligible to move from bundled tariffs to delivery services beginning May 1, 2002. (Tr. 901)

### b. <u>Delivery Charge</u>

Illinois Power rate design witness Leonard Jones and CUB/AG rate design witness Lee Smith agree that the residential DST delivery charge should be a two-block structure with the first block set at 300 kWh per month, the same structure as the energy charge in the current residential bundled rate, SC 2. (However, as discussed below, they disagree on the price differential that should be established between the first block and the tailblock.) (IP Ex. 6.1, p. 12; IP Ex. 6.11, p. 1; GCI Ex. 3, Sched. LS-6) Staff witness Lazare, in contrast, proposed a flat residential delivery charge. (Staff Ex. 14.0, p. 20; Staff Ex. 22.0, Sched. 14.3 Rev.) Mr. Lazare's proposal should be rejected, and a blocked delivery charge structure as recommended by IP witness Jones and CUB/AG witness Smith should be adopted.

As is the case with the agreed residential DST facilities charge, implementing a two block residential DST delivery charge will maintain rate continuity with the residential bundled rates. Both the Company and CUB/AG witness Smith believe that maintaining rate continuity for residential customers is an important consideration as they become eligible to switch to delivery services. (IP Ex. 6.6, p. 7; GCI Ex. 1, p. 14) In addition, a two block delivery charge for residential customers better matches the pricing to how local low voltage costs (<u>i.e.</u>, secondary distribution facilities costs) are incurred. Local secondary facilities (lines and transformers) may serve from one to a few customers, and are sized to meet the customers' maximum demands. These costs are therefore appropriately recovered through the facilities charge, or, as IP is proposing, through a first block delivery charge. (IP Ex. 6.6, pp. 11-12)

Mr. Lazare disagreed with the Company and with CUB/AG witness Smith that a two block delivery charge should be used to recover local low voltage costs in the initial block. He advocated a flat residential delivery charge in order to encourage conservation. (Staff Ex. 5.0, pp. 37-39; Staff Ex. 14.0, pp. 19-20) The Company questions whether conservation should be a consideration in setting rates for a delivery company that does not supply energy. (IP Ex. 6.6, p. 8) It is also questionable whether the small difference between the Company's proposed residential tailblock rate (2.022 cents/kWh, see IP Ex. 6.11, p. 1) and Mr. Lazare's proposed flat residential delivery charge (2.486 cents/kWh, see Staff Ex. 22.0, Sched. 14.3 Rev.), less than ½ cent per kWh, will provide any sort of meaningful conservation signal to residential delivery services customers.

Price signals sent to customers through rate design should reflect the cost of serving the customer.[49] Secondary facilities are installed as a function of the number of customers and the expected demand on the facilities; the secondary system cost is heavily weighted toward a function of the customer being connected to the utility's system. The demand or usage-sensitive portion of the cost of secondary facilities is relatively small. Therefore, it is appropriate to recover these costs in a relatively small usage block in the delivery charge. The Company has chosen to set the initial block at 300 kWh for these purposes. Eighty percent of IP residential customers use at least 300 kWh per month; further, this blocking is identical to the residential bundled rate, SC 2. (IP Ex. 6.1, pp. 11-12; IP Ex. 6.6, pp. 8-10) In addition, the cost per kWh of secondary facilities installed to serve residential customers decreases as the customer's size (in terms of average kWh

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[49] Moreover, cost-based rates provide the most appropriate price signals. (IP Ex. 6.6, p. 8) Attempting to promote conservation by implementing charges that do not reflect cost of service is an inappropriate objective.

usage per month) increases (even though the total secondary facilities cost of service increases as the size of the customer increases). (IP Ex. 6.6, pp. 8-9; Rev. IP 6.12) Therefore, use of a flat residential delivery charge as proposed by Mr. Lazare would inappropriately shift cost recovery from smaller use customers to larger use customers. (IP Ex. 6.14, pp. 7-8)

IP proposes that the differential between the first and second blocks in the delivery charge should be 1.4 cents per kWh. This is the load-weighted average of the differentials between the first and second block in the SC 2 (bundled) residential energy charge for the summer and winter seasons that will be in effect commencing May 1, 2002 (i.e., reflecting the mandated 5% residential bundled rate reduction).[50] (IP Ex. 6.6, p. 6) While CUB/AG witness Smith agreed with IP that the residential DST delivery charge should have two blocks, with the first block set at 300 kWh per month, she proposed a differential of only 0.8 cents per kWh between the blocks, which reflects only the summer season differential and ignores the winter season differential in SC 2. (GCI Ex. 3, Sched. LS-6; IP Ex. 6.6, p. 6) Ms. Smith contended that the higher differential proposed by the Company was not supported by cost of service. (GCI Ex. 3, pp. 6-7) IP acknowledges that the 1.4 cent/kWh differential is somewhat higher than the cost-based differential (i.e., the differential that would be based strictly on the recovery of secondary facilities costs in the first block). (IP Ex. 6.14, p. 5) However, IP witness Mr. Jones pointed out that the agreed residential DST facilities charges for single and multi-family service are somewhat below cost, while the agreed residential DST facilities charges for

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[50] Effective May 1, 2002, the summer differential between the first two energy charge blocks in SC 2 will be 0.8 cents per kWh, and the winter differential will be 1.76 cents per kWh. (IP Ex. 6.6, p. 6)

three-phase service (i.e., the largest use customers) are somewhat above cost.[51] Therefore, taken together, IP's proposed facilities charges plus first block delivery charge will appropriately recover facilities and secondary demand costs, for both smaller-use and larger use customers. (IP Ex. 6.14, pp. 5-6; Tr. 872-73)

In summary, IP's proposed residential DST delivery charge rate design best promotes the twin objectives of proper cost recovery and maintaining rate continuity with the residential bundled rates, and should therefore be approved by the Commission.

### 2. Small Use General Service DST Rate Design

#### a. Facilities Charges

Based on the distribution revenue requirement it proposed in its rebuttal filing, and the allocation thereof to the small use general service class based on the ECOSS, IP proposes facilities charges for small use general service DST customers of $8.03 and $11.09 for single-phase and three-phase service, respectively. IP also proposes a facilities charge for unmetered service DST customers of $8.50. (IP Ex. 6.6, p. 11; IP Ex. 6.11, p. 1) Staff witness Lazare, the only other witness to address rate design for this customer class, offered no criticisms of IP's proposed facilities charges, yet he proposed facilities charges for this class (to recover the same revenue requirement) of $5.35 and

[51] The agreed facilities charges for single- and multi-family service are below cost of service by $0.29/month and $1.17/month, respectively. The agreed facilities charge for three-phase service is above cost by $2.66/month. (IP Ex. 6.14, p. 5) This disparity between the agreed facilities charges and cost of service arises because, as described above, the parties have agreed to use the bundled SC 2 facilities charges to be in effect on May 1, 2002. These facilities charges were last established over nine years ago (Docket 91-0335 (July 8, 1992)) and by May 1, 2002 will have been subsequently reduced by two legislatively-mandated rate reductions totaling 20%, that have nothing to do with cost of service. (See Tr. 728)

$7.39 for single-phase and three-phase service, respectively. (Staff Ex. 22.0, Sched. 14.4 Rev.)

Although Mr. Lazare's rate design exhibit stated that one of his proposals was to "prorate Company-proposed customer, metering and demand charges to conform to applicable costs as determined under IP's cost of service study" (Staff Ex. 22.0), his proposal would move the small use general service facilities charges *below* cost of service. (See IP Ex. 6.14, p. 10 and Rev. IP 6.10, Sched. 2, Item 1, p. 5) Mr. Lazare offered no other offsetting considerations to justify rates different from the Company's proposal. The Company's proposed facilities charges for the small use general service class mitigate some of the rate impact of moving the prices to cost of service immediately. (IP Ex. 6.6, p. 10) IP's proposed facilities charges provide a greater degree of rate continuity and maintain the relationships between individual facilities charges and meter charges as well as costs within the small use general service class. IP's proposal provides for a progression to move prices closer to cost of service, and should be adopted. (See IP Ex. 6.14, p. 10)

**b. <u>Delivery Charge</u>**

IP proposes a two-block delivery charge for the small use general service class with the first block set at 300 kWh per month. This structure is the same as the residential DST delivery charge, for the same reasons. (IP Ex. 6.1, p. 13; IP Ex. 6.6, p. 11) Staff witness Lazare proposed a flat delivery charge for small use general service DST customers, as he did for residential DST customers. (Staff Ex. 14.0, p. 23) However, the small use general service customers tend to use less energy than the average residential customer; in fact, under the tariff definition for this customer class, a small use general service customer cannot use more than 61 kWh per day, on average, in the summer months. Further, small use general service customers are even less likely than are residential customers to share secondary facilities (lines and transformers), which would otherwise reduce the average secondary facilities costs per customer and per kWh. Thus, the cost recovery reasons that support use of a blocked DST delivery charge are even stronger for small use general service customers than for residential customers. (IP Ex. 6.14, p. 9) In addition, Mr. Lazare's proposed delivery charge recovers more revenue that IP's delivery charge due to the need to recover the remaining class revenue requirement that results from his proposed facilities charges being lower than those IP has proposed.

With respect to unmetered service, Mr. Lazare proposes to increase the delivery charge by 1176%. (IP Ex. 6.6, p. 12) The need for this large increase is the result of his proposal to reduce the unmetered service facilities charge. (See Staff Ex. 22.0, Sched. 14.4 Rev.) The Company is proposing to keep the unmetered service facilities charge at its current level ($8.50 per month), which enables the Company to mitigate the increase needed in the delivery charge in order to achieve cost recovery. (IP Ex. 6.6, p. 12)

The Company's proposed small use general service rate design is more reasonable than Mr. Lazare's proposals on both cost of service and rate continuity grounds, and should be adopted.

### 3. Demand-Metered General Service DST Rate Design

#### a. Facilities Charges

The ECOSS shows that, in general, the current facilities charges and metering charges for the demand-metered general service class do not match the overall cost of service for these components. IP proposes to set the metering charge at cost of service, since this is an unbundled service that can be provided by others; and to change the facilities charges by one-half of the amount necessary to reach cost of service recovery. This approach will mitigate the disparate impacts on the subclasses within the demand-metered class that would result from full movement to cost of service in this case. (IP Ex. 6.6, pp. 10-11; Rev. IP Ex. 6.10)

Staff witness Lazare proposed facilities charges that were scaled down from IP's proposed facilities charges. (See IP Ex. 6.14, pp. 9-10, and Staff Ex. 22.0, Sched. 14.5 Rev.) In general, IP's proposed facilities charges are closer to cost of service than Mr. Lazare's proposed charges, represent a considered step in moving to full cost-based facilities charges, and provide a greater degree of rate continuity. Accordingly, IP's proposed facilities charges for this class, rather than Mr. Lazare's, should be adopted.

**b. <u>Demand Charges and Distribution Capacity Charges</u>**

Illinois Power proposes to implement a distribution capacity charge for demand-metered DST customers. The distribution capacity charge is designed to recover the cost of local low-voltage facilities that for the most part do not share in the load diversity of the larger system. It will be billed on the basis of the customer's maximum demand in the preceding 12 months, which provides a better fit to the manner in which the costs of low voltage facilities are incurred. The distribution capacity charge will therefore operate identically to the distribution capacity charge that is included in IP's bundled rates for demand-metered customers. (IP Ex. 6.1, pp. 15-16)

The remaining demand charge will recover the cost of high-voltage facilities, which are designed primarily based on the diversity of several customers' loads. Thus, the demand charge will be billed based on the customer's maximum monthly demand. This is the basis for billing the current DST demand charges. (<u>Id</u>., p. 16) The methodology IP used to develop the proposed demand charges is explained in Revised IP

Exhibit 6.10, pp. 8-11. Staff found IP's demand charge methodology to be generally acceptable. (See Staff Ex. 14.0, pp. 22-23)

Staff witness Lazare objected to the proposal to establish a separate distribution capacity charge. The principal basis for his objection was that basing this charge on the customer's maximum demands during the preceding 12 months provides no incentive to the customer to control its monthly demands, so long as the monthly demands stay below the maximum demand in the prior 12 months. He also questioned whether distribution costs are in fact driven by individual maximum demands and do not benefit from the diversity of the overall system. (Staff Ex. 5.0, pp. 30-33; Staff Ex. 14.0, pp. 23-25)

However, the proposed distribution capacity charge based on the customer's maximum demand in the prior 12 months is consistent with cost of service principles, because it is annual customer peak demand that drives distribution investment. Indeed, the ECOSS in this case uses annual non-coincident peak demand to allocate distribution costs. (IP Ex. 6.6, p. 18) Mr. Lazare did not take issue with this cost allocation method in IP's ECOSS. In addition, once the customer has established a particular maximum demand, the distribution system must be ready to serve that level of demand in the future. (Id., pp. 18-19) Moreover, contrary to Mr. Lazare's assertion, the customer will still have an incentive to control its monthly demands, in order to be able to reduce its distribution capacity charge after 12 months pass since the prior maximum demand was established.[52] (Id., p. 18; Tr. 746-47) Finally, separation of the present demand charge into the

[52] In addition, the fact that under IP's proposed rate design there will also be a separate demand charge, billed on the basis of the customer's maximum monthly demand, will continue to give the customer a direct incentive to control the monthly demands. (IP Ex. 6.6, p. 20)

proposed distribution capacity charge (billed on the basis of maximum demand in the prior 12 months) and a demand charge (billed on the basis of maximum monthly demand) helps to prevent high load factor customers from subsidizing low load factor customers. (IP Ex. 6.6, pp. 19-20)

Mr. Lazare argued that the Commission has recently disapproved of the use of annual demand ratchets such as would be applied to bill the proposed distribution capacity charge. (Staff Ex. 5.0, p. 32) However, in the cases Mr. Lazare relied on, the utility was attempting to recover the entire delivery service charge using a demand ratchet. Here, IP is only proposing to use an annual demand ratchet for the distribution capacity charge, which will recover low voltage costs. Under IP's proposal, there will continue to be a separate demand charge to recover high voltage costs, which will be billed based on monthly maximum demands. (IP Ex. 6.6, p. 20)

Accordingly, IP's proposal for a separate distribution capacity charge for the demand-metered class, which would be consistent with the distribution capacity charge in its bundled rates, should be adopted.

#### c. Reactive Demand Charge

IP proposed to increase the reactive demand charge to 20 cents per kvar. (IP Ex. 6.6, p. 15) Staff witness Lazare proposed a slight increase above the current charge of 10 cents per kvar. (Staff Ex. 14.0, Sched. 14.5, p. 3) IIEC proposed that the reactive demand charge either be kept at the current level, or increased by an equal percentage to all other charges. (IIEC Ex. 1, p. 21; IIEC Ex. 6, p. 16) However, the parties ultimately agreed that for purposes of this proceeding, the reactive demand charge should be set at 13.0 cents per kvar. (Tr. 804-05 (Jones, IP); Staff Ex. 22.0 (Lazare, Staff); Tr. 687-88 (Stephens, IIEC))

### d. **Transformation Charges**

SC 110 currently includes transformation charges of 50 cents per kW of distribution capacity for customers with distribution capacities below 3 MW, and 75 cents per kW for customers with distribution capacities of 3 MW or more. IP is not proposing any changes to the transformation charges in this case. Nonetheless, IIEC questioned the support for the transformation charges, and in particular questioned the higher transformation charge for higher voltage (over 3 MW) customers. IIEC proposed that the transformation charge for customers 3 MW and above be re-set to the same level as the charge for customers below 3 MW, 50 cents per kW.[53] (IIEC Ex. 1, pp. 21-23)

Demand-metered customers have the option to either take transformation service from IP, or rent or install their own transformation facilities. Accordingly, the transformation charge is based on the cost of installing new transformers, plus applicable expenses, to be consistent with the economic decision the customer faces. (IP Ex. 6.6, p. 16; see IP Ex. 6.10, Sched. 2, item 4) Moreover, transformation charge revenues serve to reduce the class revenue requirement that must be recovered through demand charges. (IP Ex. 6.6, p. 16) The charge of 75 cents per kW for customers 3 MW and larger is within the range of the costs of recently installed transformation facilities. (Id.; IP Ex. 6.10, Sched. 2, item 4) However, as IP witness Leonard Jones explained, due to the fact that transformation facilities for customers over 3 MW often have to be tailored to meet

[53] Staff witness Lazare proposed maintaining a differential similar to that in current SC 110 between the transformation charges for customers below 3 MW and those 3 MW and above. However, he proposed to revise the below-3 MW charge from 50 cents to 53.1 cents per kW, and to revise the above-3 MW charge from 75 cents to 79.7 cents per kW. (Staff Ex. 22.0, Sched. 14.5 Rev.) These increases are apparently due to Mr. Lazare's proposed reductions in other charges and the resulting need to increase the transformation charges in order to recover the full class revenue requirement.

the customer's particular requirements, these larger customers can usually obtain transformation on a more cost-effective basis by owning or renting their transformation facilities.[54] (IP Ex. 6.6, p. 16-17; IP Ex. 6.14, pp. 15-16)

Finally, it should be noted that the transformation charge in IP's bundled rates is 75 cents per kW for both customers smaller than 3 MW and customers 3 MW and above. (IP Ex. 6.6, p. 16) Therefore, if the Commission concludes that there should not be a different transformation charge in SC 110 for customers below and above 3 MW, the proper solution would be to set the transformation charge at 75 cents per kW for all demand-metered customers taking transformation service from the Company. This would promote rate continuity as customers switch from bundled service to delivery services.

#### e. Standby Capacity Requirement for Self-Generation Customers Using Delivery Services for Standby Purposes

An Illinois Power customer that installs self-generation ("SG") facilities at its premises to serve all or a part of the customer's electrical load may elect to contract with a RES to provide power and energy for standby or back-up purposes during periods when the customer's SG facilities are not operating (or operating at a reduced level). Such a customer would need to use IP's delivery services to deliver standby or backup power from the RES when the customer's SG facilities are not operating. At the time the SG customer needs to use standby power from its RES, the customer will be placing onto IP's grid all or a significant part of its load that is normally served by the customer's SG facility. (Tr. 912-13) Although the customer has installed a SG facility, Illinois Power's

[54] Indeed, of 73 IP customers larger than 3 MW, 57 already rent or own their transformation facilities. (IP Ex. 6.6, p. 16)

grid still needs to be capable of serving the customer's entire load from time to time, on no notice, whether the SG customer places its entire load on the Company's grid frequently or infrequently. Thus, IP's investment in distribution facilities in order to be prepared to serve both SG and (comparably-sized) non-SG customers is the same.[55] (IP Ex. 6.6, p. 25; IP Ex. 6.14, p. 25; Tr. 914, 933-34)

Illinois Power proposes to require customers with SG facilities that wish to use delivery services for back-up or standby supply purposes to establish a standby capacity requirement ("SCR"). The SCR would be used to bill the SG customer's demand charge, distribution capacity charge (if applicable to the customer) and transformation charge (if applicable to the customer) under SC 110.[56] (IP Ex. 6.1, pp. 19-20) However, for those charges that are billed to non-SG customers on the basis of maximum monthly demands (i.e., demand charges), IP will apply a load diversity factor to the SG customer's SCR to adjust the SCR to approximate a monthly maximum demand. The load diversity factors will be taken from the load profiles used for purposes of Rider TC, and will be in the range of 75% to 85%, depending on the SG customer's size and its load factor if its self-generation were idle for a year. (IP Ex. 6.6, pp. 22-24)

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[55] For example, substations and transformers serving the customer must be sized to serve the customer's maximum expected demand at any single moment. (IP Ex. 6.6, p. 24)

[56] The proposed distribution capacity charge is only applicable to delivery services customers served at a supply line voltage of 12.47 kV or lower. (IP Ex. 5.5., p. 12) Therefore, if a SG customer is served at a supply line voltage above 12.47 kV, the distribution capacity charge will not apply. The transformation charge is only applicable to demand-metered customers for whom IP owns and operates transformers to transform voltage from IP's available supply line voltage to the delivery-voltage at which the customer takes service. (Id., p. 13) If a SG customer owns or leases its transformation (as many customers do, see IP Ex. 6.6, p. 16), the transformation charge does not apply to that customer.

Initially, the customer will specify its SCR; IP will not modify the SCR specified by the customer. However, if the customer's maximum demand subsequently exceeds the SCR, a new SCR will be established at the customer's new, actual demand level. After 12 months, assuming the SCR has not been exceeded, IP will review the customer's demands and connected loads to determine if the customer's SCR should be reduced. (IP Ex. 6.6, p. 21) In addition, if the SG customer's maximum demand in a month exceeds its current SCR by more than 10%, the customer will be billed three times the applicable charges that are billed based on SCR, times the incremental maximum demand for the month in excess of 110% of the customer's current SCR. (IP Ex. 6.6, p. 21; IP Ex. 6.14, p. 17)

IIEC witness Stephens and Staff witness Haas objected to the proposed SCR provision. The reasons which one or both of these witnesses stated for their opposition were the following: that the SCR provision would treat SG customers differently from non-SG customers in billing the applicable charges; that the application of three times the demand charges to actual demand in excess of 110% of the customer's SCR was not based on cost of service and would give the customer an incentive to over-estimate its SCR; that it did not recognize the possibility of load diversity among SG customers in placing their standby demands on the Company's system; and that it would discourage the installation of cost-effective self-generation facilities. (IIEC Ex. 1, pp. 16-19; IIEC Ex. 4, pp. 13-14; Staff Exs. 9.0 and 18.0) However, their objections to do not justify rejecting the Company's SCR proposal.[57]

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[57] Several aspects of IP's SCR proposal were added or modified in rebuttal in response to criticisms expressed in Messrs. Stephens' and Haas' direct testimonies, including the addition of the load diversity adjustment factor, the provision of a 10% "deadband" above

The contention that the SCR provision results in SG customers being treated differently from non-SG customers is exaggerated at best. For those charges that are billed to non-SG customers based on the customer's maximum demand in the prior 12 months (i.e., the distribution capacity charge and the transformation charge, if these charges are applicable to the customer), the SCR requirement is likely to produce similar results as would occur if the SG customer's generating facility went down once per year at a time when the customer's load was high. That is, the customer's SCR and its distribution capacity (the basis used to bill distribution capacity charges and transformation charges to non-SG customers) are likely to be similar. Further, as noted earlier, IP will review the SG customer's SCR every 12 months to determine if it should be lowered. (IP Ex. 6.1, p. 20; IP Ex. 6.6, pp. 21-22) With respect to the demand charge, which is billed to SG customers on the basis of maximum monthly demands, the application of the load diversity factor to the SG customer's SCR will result in a billing determinant that approximates the customer's maximum monthly demand if its generation were idle (IP Ex. 6.6, p. 23), resulting in the SG customer being billed in a manner consistent with non-SG customers.

However, the fact is that SG customers and non-SG customers *are* different. Although both types of customers are receiving the same service from IP – no-notice access to the delivery system for the customer's entire load (IP Ex. 6.14, p. 22) -- the SG

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the customer's SCR before the triple demand charges would apply, and the provision that IP will review the customer's SCR after 12 months to determine if it should be reduced. (See IP Ex. 6.6, pp. 21, 22-23; Tr. 921) In fact, Mr. Stephens, in his rebuttal testimony, endorsed the load diversity factor adjustment feature. (IIEC Ex. 4, p. 15) Staff witness Haas also agreed that the load diversity factor would "bring Demand Charges applied to SG customers to a point more in line with the Demand Charges that non-SG customers would pay based on their monthly non-coincident peak demands." (Staff Ex. 18.0, p. 5) customer using delivery services for standby purposes is asking IP to stand ready to serve the customer's entire load that is served by the SG facility (Tr. 933-34), yet the customer may place this entire load (or any substantial part thereof) on SC 110 only occasionally. As a result, if the SG customer were billed under SC 110 only based on its actual monthly demands, it would not pay for the cost of this service.[58] This would necessitate higher charges to non-SG customers to recover the total class cost of service, i.e., other customers would be subsidizing the SG customers. (IP Ex. 6.1, p. 20; IP Ex. 6.6, pp. 22, 25-26) In contrast, the non-SG customer can be expected to have much more consistent demands on IP's system each month (IP Ex. 6.14, p. 21); therefore, use of the non-SG customer's actual monthly and annual (prior 12 months) maximum demands will result in proper cost recovery.

The provision whereby a SG customer is billed three times the applicable demand charges for incremental demands in excess of 110% of the customer's SCR is not intended to be cost-based. Rather, it is intended to discourage the SG customer from underestimating its standby capacity requirement and thereby avoiding paying for its full cost of service. This provision is intended to give the SG customer an incentive to accurately estimate and contract for the level of delivery services that the customer requires IP to be ready to provide on no notice. (IP Ex. 6.14, pp. 18-19) Moreover, such tariff provisions that are applicable in the event of a customer exceeding a stated contract amount are not new. For example, IP's gas tariffs for demand metered customers (SC 65

[58] For Illinois Power and other Illinois utilities, demand charges are set so as to recover the annual demand cost through a charge that is assessed on a monthly basis. (Tr. 936) Thus, if an SG (or any other) customer is only billed a demand charge in some but not all months of the year, the annual demand cost to serve the customer would not be recovered from that customer.

and 76) contain a provision to charge customers an Excess MDQ Charge of three times the demand charge for the excess demand over a stated Maximum Daily Quantity. Similarly, IP's gas transportation tariffs (and those of other Illinois gas distribution companies) impose charges of $6 per therm if the customer takes unauthorized overrun gas. (IP Ex. 6.14, p. 19)

In any event, designating the SCR should not be a guessing game for the customer. A customer sophisticated enough to have installed and be operating SG facilities sized to serve all or part of the load at its premises, and to have arranged for standby service from a RES, can be expected to have an accurate estimate of the load that is served by its SG facilities, and the amount of load that would be switched to the customer's standby source, and therefore to IP's delivery system, if the SG facility were not operating. (See Tr. 879-81, 916-17) Further, IP's SCR provision gives the customer a 10% margin of error before the triple demand charges apply. (IP Ex. 6.6, p. 21)

With respect to the contention that the SCR provision does not recognize the load diversity of SG customers on IP's system, IP at present has only 9 SG customers on the almost 800 circuits in its system, and no two of those SG customers are served on the same circuit. Therefore, these SG customers do not provide any load diversity benefits. The level of investment in distribution facilities to provide, or stand ready to provide on no notice, delivery service to these SG customers is the same as it is for non-SG customers. Indeed, it would be irresponsible for IP to assume that an SG customer's SG facility will always be running at the time of the peak demand on the circuit that serves the customer. To do so would risk a degradation in reliability. (IP Ex. 6.6, pp. 24-25; IP Ex. 6.14, p. 20) As Staff witness Haas acknowledged, Illinois Power's grid needs to continue to be capable of serving the customer's entire load; IP cannot reduce the load-carrying capability of the circuit that serves the SG customer by the amount of the capacity of the customer's SG facility. (Tr. 913-14)

Finally, with respect to the contention that the SCR provision will discourage the installation of cost-effective self-generation, IP reiterates that a customer sufficiently sophisticated to have designed, installed and operate an SG facility to serve all or part of its load should be capable of accurately estimating its SCR, particularly in light of the 10% cushion before the triple demand charges apply. Moreover, it is extremely unlikely that either the need to pay demand, distribution capacity and transformation charges based on the SCR under the Company's proposal, or the threat of occasionally having to pay the triple demand charges, will adversely impact a customer's decision to install and use SG facilities. The investment in the SG facility, the cost of fuel and other operating costs for the SG facility, and the market price of power the customer may have to pay to its third party supplier for standby power if its SG facility is out of service, will far outweigh IP's delivery services charges in the customer's economic calculations. (IP Ex. 6.14, p. 21)

Accordingly, IP's proposed standby capacity requirement provision for self-generation customers using delivery services for standby purposes, as modified by Mr. Jones in rebuttal, should be approved.

#### 4. Lighting DST Rate Design

Under the proposed tariffs, rates for Outdoor Area Lighting have been separated into residential and non-residential, in light of the availability of delivery services to residential customers commencing May 1, 2002. For non-residential Outdoor Area Lighting service and Municipal Street Lighting service, the current charges for each type of bulb have been adjusted on a pro rata basis to arrive at the total non-residential Lighting revenue requirement. IP developed the proposed residential DST rates for Outdoor Area Lighting in the following manner: First, the current Outdoor Area Lighting bundled rates were adjusted for the 5% rate reduction scheduled for May 1, 2002. Second, the marginal cost of energy that was used to develop the prices for existing bundled Outdoor Area Lighting service was subtracted from the adjusted bundled price for each type of bulb. This step is consistent with the manner in which the non-residential Lighting DST rates were developed in the 1999 DST Case. Finally, the charges for each type of bulb were further adjusted pro rata to arrive at the total residential Lighting revenue requirement. (IP Ex. 6.10, p. 13) No other witness proposed any alternative rate design or prices to IP's proposal for the Lighting rates.

### 5. Meter Charges for DST Customers

As discussed in Section III.A.1 above, Illinois Power determined the revenue requirement for meters subject to unbundling, and presented an ECOSS for meters subject to unbundling to allocate the meter revenue requirement to the customer classes. The meter revenue requirement was calculated using the same criteria that were approved in the meter unbundling case, Docket 99-0013. Based on the results of these studies, the Company has proposed non-residential meter charges (i.e., for small use general service and demand-metered general service DST customers) that recover the embedded cost of service. (IP Ex. 6.6, p. 11; IP Ex. 6.10, pp. 6-8) Staff witness Lazare has proposed essentially the same meter charges as the Company, with a one to two cents difference in the monthly metering charges to small use general service customers, apparently due to rounding in attempting to arrive at the total class revenue requirement. (Staff Ex. 22.0, Sched. 14.4 Rev. and 14.5 Rev.) No other party presented meter charges that differed from the Company's proposed charges. Accordingly, Illinois Power's proposed meter charges for the small use general service and demand metered general service classes should be approved.

## IV. IP'S TARIFF TERMS AND CONDITIONS ARE JUST AND REASONABLE AND SHOULD BE APPROVED

### A. In General, IP's Efforts at DST Simplification and Reorganization Have been Successful and Not Contested

As a part of its filing, IP chose to undertake a re-write of its DST and related tariffs for several purposes. *First*, the Company wanted to reorganize its tariffs to put them into the format suggested by the Commission's Order in the "Uniformity" proceeding (Docket 00-0494). (IP Ex. 5.1, p. 4) As Staff has acknowledged (Staff Ex. 7.0, pp. 5-6), IP was successful in this endeavor.

*Second*, the Company wanted to improve the understandability of its tariffs by making them more user-friendly. (See IP Ex. 5.1, p. 3; IP Ex. 7.1, p. 3) This process required a substantial re-writing of IP's tariffs. (See generally IP Ex. 5.1, pp. 3-17; IP Ex. 5.2) For example, most definitions were consolidated in IP's Standard Terms & Conditions instead of being repeated in several tariffs. Further, certain services were moved from base tariffs to Riders. For example, IP moved its Interim Supply Service ("ISS") from SC 110 to a new Rider ISS. (See IP Ex. 5.9) Also as a part of the simplification process, IP eliminated various appendices to its tariffs wherever possible. Finally, IP introduced several new options for customers or RESs so that these parties could pick, for example, different off-cycle switching methods. (IP Ex. 7.1, pp. 6-8) With these choices came different fees so that the party choosing a specific option not only pays an appropriate price for the service, but also thereby can readily see how different choices will cost more or less. (Id.) As demonstrated by the lack of objection to most of IP's changes, IP's efforts at tariff simplification have generally been successful. A few remaining issues are discussed below in other parts of this Section IV.

*Third*, IP updated its tariffs to accommodate residential customer choice. Generally, this meant including residential customers in the group of customers eligible to be served under the applicable tariffs, as well as establishing rates for residential delivery services (as discussed in Section III, above). In a few places, however, IP made special accommodations for residential customers. For example, as discussed in more detail below in Section IV.E, IP decided that an alternative should be available to residential customers who find themselves on ISS during a very high price period. Except as discussed below, no party took issue with IP's efforts to include residential customers in its DSTs.

Based on the above discussion and in light of the evidence discussed below, IP's tariffs should be approved as originally proposed in this case (or as modified by IP in subsequent testimony in response to criticisms or suggestions by Staff and other parties).

### B. IP Proposed (and No Party Objected to) Miscellaneous Fees for Various Services

#### 1. IP Proposed Several Off-cycle Switching Options and Fees Associated with Each

Off-cycle switching is a service that permits customers to begin taking delivery services on a date other than on the date that would be used in the normal course of business (i.e., the next regularly scheduled meter reading date that occurs seven days after the submission of the DASR). Originally, IP required an enrollment process for off-cycle switching but has now proposed eliminating that process; under the revised process, the RES submitting the DASR will only need to check the appropriate field on the DASR to elect off-cycle switching. (See IP Ex. 7.1, p. 6) Furthermore, off-cycle switching currently requires a manual process by both IP and the RES, with an associated fee of $50. (Id.) Now, IP is proposing to permit off-cycle switching via EDI as well. (Id.) In setting its fees for this service, IP determined that four categories should be used based on whether the off-cycle switching request was manual or EDI and whether the customer had an interval meter. (Id., p. 7) The differences in fees for each category are due to the facts that manual submissions require more time to be processed by IP personnel and that verifying billing information for customers with interval meters takes IP personnel longer. (Id., pp. 7-8) Based on these differences, IP demonstrated that the cost-based fees for each category of off-cycle switching should be:

EDI/non-interval meter: $10.00 per meter/account

EDI/interval meter: $30.00 per meter/account

Manual/non-interval meter: $17.00 per meter account

Manual/interval meter: $37.00 per meter account

(See IP Ex. 7.1, pp. 7-8; IP Ex. 8.1, p. 6; IP Ex. 8.5) These fees are in addition to applicable DASR and termination fees associated with the switch. (IP Ex. 7.1, p. 8)

No party objected to IP's new off-cycle switching options or the associated fees, and no party presented any evidence contesting IP's demonstration that the fees are just and reasonable. Based on the evidence in the record, IP's off-cycle switching options and associated fees should be approved.

#### 2. IP Has Developed a PPO Calculator and Proposed a Fee for Those Who Wish to Use It

IP currently offers the Power Purchase Option ("PPO") pursuant to § 16-110 of the PUA and its Rider PPO. PPO service permits those customers who have a positive Transition Charge ("TC") to take delivery services from IP as well obtain their power and energy from IP at the same price as was used to calculate their TC. This generally provides those customers with savings compared to the amount they would pay on bundled rates. The exact difference varies from customer to customer and thus, RESs, customers and their agents frequently want to estimate what savings are achievable before deciding on a course of action. IP performed the necessary calculations for customers and RESs manually at first. (IP Ex. 7.1, p. 8) However, IP has now developed a web-based PPO Calculator that permits RESs, customers and agents to perform the calculations on their own. (Id., pp. 8-9) The calculator works by taking a customer account number and meter number and then automatically populating the data and performing the necessary calculations. (Id., p. 9) The result is a comparison of PPO pricing to the customer's existing bundled service classification. (Id.)

Currently, IP does not charge a fee for PPO comparison calculations (whether done manually or by a RES/customer using its calculator). (Id.) However, this service has obvious value to both RESs and customers. Accordingly, IP has proposed fees for this service. (Id.) In particular, IP proposes a fee of $4.50 per service classification calculation per account if the RES or customer uses the web-based calculator and $12.50 per service classification calculation per account if IP performs the calculation manually for the requestor.[59] (Id.) The cost difference is based on the increased time IP personnel must devote to manual calculation requests. (See IP Ex. 7.1, pp. 9-10; IP Ex. 8.1, pp. 5-6; IP Ex. 8.3)

[59] In both cases, $1.00 of the fee is for providing the customer consumption data needed in the calculation while the remainder is for the analysis. (IP Ex. 7.1, p. 9)

IP's evidence demonstrates that the fees it is proposing are cost-based and just and reasonable. No party objected to either IP's PPO calculator or the fees IP has proposed, nor presented any evidence that IP's proposed fees were not just and reasonable. IP's proposed PPO calculator fees should be approved.

### 3. IP Proposed Monthly Fees for Those RESs and Agents Who Obtain Customer Usage Data via IP's Web-site, Including via the PPO Calculator, and Who Prefer a Flat Fee

Generally, customers and their authorized agents, as well as RESs, can obtain customer usage data from IP by requesting it and paying a fee for each such request. IP accepts EDI and manual requests and has developed a variety of web-based services.[60] (See generally IP Ex. 7.1, p. 4) To provide RESs and agents with an alternative to paying a separate fee for each request for customer data, IP has proposed a monthly charge of $47.00 for any RES or agent that obtains customer data via IP's web-based applications (including its PPO calculator, described above). (IP Ex. 7.1, pp. 4-5) This fee was developed based on an assumption of likely usage by a RES or agent over a 12-month period and, therefore, IP will require that those choosing this option enter into a contract for a 12-month period. (Id., p. 5) IP presented evidence of the cost-basis for its proposed fee. (See IP Ex. 8.1, p. 6; IP Ex. 8.4)

RESs and agents do not need to pay the monthly fee. Instead, they can choose to continue paying the separate charge each time they request customer data. Furthermore, requests for interval metered data, manual requests and EDI requests will continue to be assessed a separate fee. (IP Ex. 7.1, p. 5)

[60] The web-based applications do not include data for customers whose load is 1 MW or greater, in light of the agreement reached in the Uniformity docket. (See IP Ex. 7.1, p. 5)

No party objected to IP's monthly fee, nor did any party present any evidence disputing the cost basis for the fee. IP's proposed monthly fee for these services should be approved.

### 4. IP's Updated Single Bill Option Credits Should Be Approved

In IP's 1999 DST Case, the Commission developed a method to determine the credit a RES receives when it undertakes to bill the retail customer for both its own charges and IP's delivery services charges. (See 1999 DST Order, pp. 126-30) The adopted methodology used embedded costs to set the credit. (See id., pp. 129-30) IP updated this analysis for the current case using more recent data but employing the same methodology that was approved in the prior case. (IP Ex. 8.1, p. 7)

Although the same cost categories apply to both residential and non-residential customers, IP developed separate fees for these two groups because of a difference in uncollectible expenses between the two groups. (Id.) Separate fees were also determined based on whether the RES assumes responsibility for payment and whether the customer is an electric-only customer or a combination gas and electric customer. (Id., p. 8) In the latter case, IP must continue to send a bill to the customer and, therefore, continues to incur the costs of preparing a bill. (Id.) Under these circumstances, the only time a credit is warranted is when the RES assumes responsibility for payment. The SBO credits, based on the evidence in this record, are as follows: (1) \$0.439 and \$1.133, for residential and non-residential electric-only customers, respectively, if the RES assumes responsibility for payment; (2) \$0.213 for residential and non-residential electric-only customers if the RES does not assume responsibility for payment; and (3) \$0.226 and \$0.920, for residential and non-residential combination customers, respectively, applicable only if the RES assumes responsibility for payment. (See IP Ex. 8.1, p. 8; IP Ex. 8.7)

No party objected to IP's evidence or presented evidence supporting a different credit. Based on the undisputed evidence in the record, IP's SBO credits should be approved as proposed.

#### 5. IP Has Proposed a Standard Copying Fee

IP proposed a standard copying fee of $0.25 per page for requests for copies other than customer usage and PPO calculator requests. (See IP Ex. 5.1, pp. 5-6; IP Ex. 5.3, p. 7) No party objected to this fee, nor did any party present evidence that a different fee would be more appropriate. Indeed, because most items can be obtained electronically (for example, IP maintains its tariffs on its web-site, (IP Ex. 5.1, p. 6)), the need for copying should now be minimized, and any associated costs should be imposed on those who insist on receiving paper copies of documents. Furthermore, the fee IP proposes is the same as the fee established by the General Assembly for the Commission to charge for copies. (See Section 2-201 of the PUA) Based on the record, IP's proposed copying fee should be approved.

### C. IP's Updated Transition Charge Tariff Should Be Adopted

#### 1. IP's Revisions to Rider TC to Accommodate Residential Customers Should Be Approved

Currently, IP has in place Rider TC to calculate a customer's TC either individually or on a class basis, along with a market value index ("MVI") tariff (Rider MVI) to set the market price of the power and energy used in calculating TCs. To accommodate residential customers who take delivery services, IP has updated Rider TC. (See generally IP Ex. 6.1, pp. 23-27 and IP Ex. 5.7) IP proposes to calculate only group

TCs for residential customers. While the PUA requires individual TC calculations for customers with loads greater than 1,000 kW, IP voluntarily calculates individual TCs for customers over 100 kW. Nonetheless, even this lower limit remains substantially above the typical residential customer's demand of about 5 kW. (See IP Ex. 6.1, p. 23)

To avoid disproportionate impacts that could be seen by individual residential customers if only a few TC groups were established for TC calculations, the Company has created multiple TC groups for each of its current residential service classifications (SC 2 and SC 3). (Id., p. 25) The groups are based not only on which service classification the customer is served, but also on such factors as usage, whether the customer is a space heat or non-space heat customer, and whether service is single phase or three phase. (Id., p. 24) This results in TC groups that have more homogeneity, and therefore, more equitably sets TCs for all parties. (Id., p. 25) Furthermore, the Company's rationale and approach is similar to the one it uses in determining non-residential TCs.

No party has objected to IP's revisions to Rider TC. Given the evidence in the record on these revisions, they should be approved by the Commission.

#### 2. IP's Updated Values for Uncollectible Expense and Retail Marketing Expense Used to Adjust the Market Value Should Be Adopted

One adjustment made to the market values used in calculating TCs is for marketing and uncollectible costs. (See 1999 Order, p. 110) IP updated this adjustment based on test year costs and expenses as derived from FERC Form 1. (IP Ex. 8.1, p. 9) No party objected to IP's evidence, nor did any party provide alternative values. Thus, IP's updated values should be approved.

### 3. IP's Updated Value for Energy Imbalance Costs (Factor A4c) Should Be Approved

Currently, IP's delivery service revenue used to calculate TCs includes a factor (known as Factor A4c) for energy imbalance revenues.[61] (See IP Ex. 5.1, p. 13) At the time this factor was established, IP's Open Access Transmission Tariff ("OATT") permitted IP to retain energy imbalance revenues it received in excess of its costs. (Id.) Since that time, however, IP's OATT has changed such that IP must credit energy imbalance revenues in excess of its costs back to transmission customers. (Id.) Therefore, IP's net imbalance revenues (after the credit is included) will calculate to 0. (Id., pp. 13-14) Given this fact, IP has proposed setting Factor A4c at 0.

No party has objected to IP's evidence on this point, nor presented any evidence that a different value for Factor A4c is appropriate. Based on the evidence in the record, IP's revised Factor A4c should be approved.

## D. Revised Rider PPO Should Be Approved

IP has proposed a number of changes to its current PPO tariff (Rider PPO).

### 1. IP's Proposal to Add Factor A4c (for Energy Imbalance Costs) To Rider PPO Should Be Approved

As explained in Section IV.C.3 above, Factor A4c adds to the delivery service revenue component of the TC calculation an amount to reflect IP's net revenues from energy imbalance service. Because of the equation used for calculating TCs, this addition lowers the TCs paid by a customer. PPO customers (who to be eligible must have a positive TC) are not charged for energy imbalances. (See IP Ex. 5.1, p. 15; 1999 DST Order, p. 118) Therefore, these customers should not receive a credit, in the form of

[61] The factor is actually a net figure, calculated by subtracting IP's related costs from the revenues it receives for energy imbalance service. (IP Ex. 5.1, p. 13)

lower TCs, for delivery services charges they do not pay. (Id.) To fix this problem, IP proposes adding Factor 4Ac to the price a PPO customer pays under Rider PPO. (Id.) For purposes of this case, this change will have no impact on any customer because Factor A4c is being set at 0 (as explained above). Furthermore, because this addition occurs after it has already been determined that a customer (a) has a positive TC (when calculated using the credit) and (b) has decided to take PPO service, no customer will lose its eligibility for PPO due to the inclusion of this Factor.

The only party to oppose this change to Rider PPO is IIEC. IIEC does not dispute any of the facts relating to this change, including the fact that initially the change has no effect on customers. (See IIEC Ex. 1, pp. 32-33) Rather, IIEC's concern focuses on perceived "uncertainty" as to the events that might cause Factor A4c to become positive in the future. (Id., p. 32) Regardless of what events might transpire in the future to alter Factor A4c, the IIEC does not (and cannot) dispute that under their proposal to omit this Factor from Rider PPO, PPO customers will be receiving a credit in the calculation of their TCs for charges they do not pay because no imbalance charges are paid by PPO customers. (See IP Ex. 5.11, p. 18) In fact, this asymmetry can have a negative effect on a RES' ability to serve these customers: the total price of service under PPO (an alternative available to any non-residential customer with a positive TC) is reduced below what it should otherwise be making it harder for RESs to compete for these customers' business. (IP Ex. 5.11, p. 18)

IIEC's only response is that if Factor A4c should become positive in the future, IP can then file to add it to Rider PPO. (IIEC Ex. 1, pp. 32-33; IIEC Ex. 4, p. 29) This response ignores the fact that such a change may take time to be approved and implemented, creating a period during which PPO customers receive an unwarranted benefit and RESs are at a disadvantage competing for that business. Given IIEC's repeated diatribes regarding the pace of competition (IIEC Ex. 1, pp. 5-7; IIEC Ex. 4, pp. 2-6), its position on the addition of Factor A4c is curious.

In any event, given the logical consistency created by including a Factor A4c off-set in Rider PPO, and the paucity of compelling reasons for not making this change at this time, IP's proposal to add Factor A4c to Rider PPO should be approved.

### 2. An Additional Charge to Recover the Cost of Required Payments to the State of Illinois Energy Efficiency Fund Should Be Approved

Initially, IP included its *pro rata* share of the annual assessment under the Renewable Energy Efficiency and Coal Resources Development Law of 1997 in its distribution operating expenses as part of the distribution revenue requirement. After reviewing Staff's position on this expense, the Company agreed that this assessment (which is based on kWhs sold and not kWhs delivered) should not be recovered through its delivery services charges. (IP Ex. 5.11, pp. 1-2) Accordingly, IP excluded its assessment from its revenue requirement. (See Section II.C.2, above; IP Ex. 5.11, pp. 1-2; IP Ex. 1.34, p. 30; Rev. IP Ex. 3.24, p. 3, col. (33)) However, for consistency, IP proposed that those customers served under SC 110 who take energy supply from IP (i.e., PPO customers and those on ISS) pay their ratable share of this expense. (IP Ex. 5.11, p. 2) Based on the total test year assessment divided by the total Company kWhs sold in the test year, the incremental charge is 0.0025¢/kWh. (Id.) No party objected to IP's proposed addition to the PPO or ISS charges nor did any party present any evidence for a different charge for this item. The additional charge of 0.0025¢/kWh for energy sold under Riders PPO and ISS should be approved.

### 3. IP's Pricing Options for Non-Firm PPO Customers During Higher Energy Periods and Buy-Through Situations Should Be Approved.

IP has proposed another change to Rider PPO to address a situation that can arise for those customers who take non-firm PPO service. Currently, under Section 8 of Rider PPO, if the Company invokes the higher energy or buy-through provisions of its interruptible rates, the charge to the customer is the price specified in the applicable interruptible service classification. Assuming the market value used in setting non-firm PPO prices is below the higher energy or buy-through energy price, this sends the proper signal for customers to either curtail their loads or pay the higher price. However, if the non-firm PPO market value is in fact above the applicable higher energy or buy-through rate, then the intent behind these rates (which is to serve as an alternative to curtailing load) is defeated. (See generally IP Ex. 5.1, p. 14) To alleviate this possibility, the Company proposed setting the non-firm PPO price at the higher of the non-firm MVI price or the otherwise applicable higher energy/buy-through price. (Id.) No party objected to IP's proposal, nor offered an alternative to this proposal. IP's proposed change to non-firm PPO pricing should be approved.

### 4. IP's Proposed Clarification that PPO Billings Should Include an Adjustment to Reflect the Transmission Energy Loss Factor Should Be Approved

IP proposes that Rider PPO include additional language that clarifies an issue so that PPO customers realize that they are not paying for transmission losses twice. The issue arises because the market values set forth in Rider TC (which are also used to bill a customer energy under Rider PPO) have been adjusted for both transmission and distribution losses. However, the PPO customer already pays for transmission losses under Schedule 9 of the OATT. Therefore, IP proposes to include language in Rider PPO to clarify that a customer's billing for power and energy will be reduced by the transmission energy loss factor. (IP Ex. 5.1, p. 15) Once again, no party objected to IP's proposed change, nor offered any alternative. Based on the record in this case, IP's proposed change should be approved.

### E. <u>IP's Proposed Rider ISS Should Be Approved</u>

Currently, IP's ISS provisions for delivery services customers are contained in SC 110. As a part of its tariff re-write process, IP proposes moving this service to a separate rider (Rider ISS) and adding certain language to accommodate residential delivery services customers. Otherwise, the service remains as it is in IP's current tariffs. Several parties have raised various issues with IP's Rider ISS (including two issues relating to aspects of ISS that IP has not proposed to change from the *status quo*). These are addressed below. Before doing so, however, we provide some background.

IP's current pricing for ISS is based on its Real Time Pricing ("RTP") rate, as approved by the Commission in IP's 1999 DST case. (1999 DST Order, pp. 123-24) The purpose behind this pricing mechanism is that

> [D]efault service *should be temporary in nature and that it must not be a vehicle for rate arbitrage*. For this reason, the Commission rejects Enron/NEV's suggested modification to allow a customer to simply return to bundled service at no notice. Similarly, the Commission finds no support for IIEC's suggestion that a customer be allowed to return for ninety days, which the Commission notes, would roughly parallel the period of time associated with the seasonal shift to summer rates, which tend to be higher than rates charged during other times of the year.

(<u>Id.</u>, p. 124 (emphasis added)) The Commission's language has proven prescient because, in fact, thus far, no customer had been on ISS in IP's territory due to a RES defaulting and ceasing to do business. (IP Ex. 11.2, pp. 1-2) Rather, two dozen customers have been on ISS for other reasons, mainly due to the customer's (or its RES') actions or inactions. (See generally IP Ex. 11.2) Furthermore, the experience of actual customers on ISS shows that IP's ISS pricing must not be too high since most of the customers on ISS have not used off-cycle switching to get off the service faster. (Id., pp. 1-2) Indeed, two customers stayed on ISS for the maximum period permitted (two meter reading dates). (Id., p. 1)

### 1. IP's Pricing for Interim Supply Service for Residential Customers is the same as For Non-Residential Customers, But with Payment Flexibility During Certain Periods

In setting the ISS price for residential customers, IP chose to use the same pricing mechanism that it uses for non-residential customers. (See IP Ex. 5.1, p. 16; IP Ex. 5.9) The Commission previously approved this price. (1999 DST Order, p. 124) Further, no party has pointed to any facts that have changed to make this pricing unjust or unreasonable. IP recognized, however, that some residential customers might face unusually high monthly bills if they found themselves on ISS during high price months (such as summer months). (IP Ex. 5.1, p. 16) To alleviate concerns if this were to occur, IP proposes to offer a service under which a residential customer whose ISS price was more than 120% of the customer's average bundled bill could choose to have the amount above 120% spread out over three months in those instances where the difference is more than $25. (IP Ex. 5.1, p. 17) The customer would pay interest on the portion that was being spread over the additional months, but would also see a somewhat levelized bill. Of course, the customer could also choose to pay the whole bill by the regular due date and avoid interest payments. (Id.)

Of note, the intervenors representing residential customers in this case (CUB and the AG) have not objected to IP's proposal for residential ISS. Rather, it is Staff that objects to IP's residential pricing plan. Staff prefers that residential ISS be priced at the bundled rate plus 10%. (Staff Ex. 6.0, p. 3) The basis for Staff's proposed pricing is Staff's assertion that residential customers may fear that they will not be able to afford very high ISS pricing in the event they find themselves on ISS at some point and thus a "barrier to enter[ing]" the market has been created. (Id., pp. 3-4) Staff makes this proposal despite the fact that even Staff recognizes that the Company could incur wholesale prices substantially above the price it could charge under Staff's proposal. (Id., p. 3 ("Illinois utilities have paid high, and sometimes extraordinary, prices for power to serve summer demand."))

Staff's proposal (and its rationale) ignores several key facts. First, residential customers who have decided to take delivery services are the very ones who have already shown themselves to be less averse to market prices. In fact, Staff recognizes that market-based pricing is the type of price customers are likely to see from the competitive market and from their alternative suppliers. (Tr. 532-33) Furthermore, the chances of a residential customer ending up on ISS would seem to be small (as a comparison, only about 2.5% of non-residential customers who have been on delivery services have subsequently been on ISS since choice began in 1999 (Tr. 434-35)). Taken together, it seems unlikely that those residential customers who want to take choice (and are thus willing to pay a market price) will find the small, added risk that they will in fact pay a market price for a short period in the unlikely event that they end up on ISS (a service they may not even realize exists) to a be a significant barrier to their taking choice. Indeed, Staff offered no hard evidence to the contrary, but rather provided only its conjecture.

Staff's proposal also fails to recognize that IP's bundled rates were last set almost a decade ago, with the goal of collecting annual revenues over an annual period. (IP Ex. 11.1, p. 5) These rates were *not* intended for short-term application, nor were they set with the goal of recovering short-term, seasonal costs. (Id.) In addition, with the mandatory rate reductions for residential customers, bundled rates plus 10% will not even recover the rates approved by this Commission in IP's last general electric rate case.

Furthermore, Staff failed to meaningfully address the problems raised by its pricing proposal. Staff freely acknowledged that, under its proposal, IP could face costs to procure ISS power and energy that far exceed the price the Company could charge. (See, e.g., Tr. 535) Staff's "solution" was to make up the difference in a later rate case. (Tr. 536-37) Nonetheless, Staff could not guarantee that all excess expenditures outside a future test year would be recovered by the Company. (Tr. 537) Nor could Staff explain how its proposal comported with such standard ratemaking concepts as the prohibition on recovering deferred costs and retroactive ratemaking. (Tr. 537-38).

Of particular note, under Staff's proposal, any excess ISS costs incurred by IP would be socialized across all customers who take delivery services at some future time, rather than having those specific customers who cause the Company to incur these excess costs pay those costs at the time they are incurred (with an option to ameliorate some of the immediate burden if the ISS price is truly above the norm). Staff never explained how this is good policy. Equally disconcerting was Staff's inability to address the stark analogy to California's woes (where it was widely reported that utilities faced ruin when forced to buy at competitive wholesale prices, but could only charge a fixed rate). (Tr. 536) Here, the amounts may not be as great as in California, but could nonetheless be millions of dollars. (IP Ex. 11.1, p. 4) In any event, even Staff recognized that IP is under no obligation to offer ISS service (at any price). (Tr. 539) And, IP's ISS is superior to no ISS at all. (Tr. 539-40)

Because IP's proposal best balances the needs of customers (both those who end up on ISS and those who do not) and the Company, it should be adopted. Staff's proposal should be rejected because it fails to adequately address a host of issues raised by using a fixed retail price for a short-term pricing option that could lead to the Company incurring costs far exceeding the amounts it can collect contemporaneously from customers under Staff's proposal.

**2. The IIEC's Concerns With ISS Pricing Should Be Rejected**

In contrast to Staff, IIEC does not disagree with the use of RTP pricing to set the ISS energy price. (See IIEC Ex. 1, p. 25) Rather, IIEC disagrees with the way the base cost of energy is adjusted and the way transmission service is priced for ISS customers. (Id., pp. 25-27) The short answer is that neither of these represents changes from IP's current tariffs on file with the Commission, as approved in the 1999 DST Case.[62] (Compare Current SC 110, p. 44 with IP Ex. 5.9, p. 2) Therefore, these issues are not properly before the Commission for review at this time. However, even if this were not the case, IIEC is wrong on both points.

With respect to the adjustments to the base energy component, IIEC and IP at least start from the same point: "Rider ISS is not Rider DA-RTP." (IIEC Ex. 1, p. 26) From there, however, IIEC and IP diverge dramatically. In particular, IIEC disagrees with IP adding either the recovery factor in DA-RTP or a 10% adder. IIEC thus appears

[62] The one proposed change in the pricing in the current ISS provisions in SC 110 relates to ancillary services and was not contested by any party.

to believe that DA-RTP (a bundled service that is intended to apply to a customer's *incremental* load with rates set to be collected over a period of at least one year) should be priced *higher* than ISS (an unbundled service whereby the utility may be required to serve a customer's entire load on no notice for a very short period when energy prices may be extraordinarily high). On its face, this is absurd. Indeed, given the nature of the service, ISS could easily be priced at a premium. In no case should it be priced at a discount. (See IP Ex. 11.1, p. 12)

Leaving aside the absurdity of IIEC's position, its proposal fails to meet the Commission's goal of preventing rate arbitrage. In periods of high market prices, customers and RESs who realize that they can obtain power and energy at a price that does not reflect the market price of the service they are receiving will have every incentive to take advantage of this service.[63] (IP Ex. 11.1, p. 14) Facts belie any contrary assertion by IIEC. As currently priced (i.e., not at the lower prices urged by IIEC), RESs and their customers have chosen to use ISS as bridge pricing even though they had options available to avoid taking ISS service. (IP Ex. 11.1, p. 13) Furthermore, the record is devoid of any evidence of customers or RESs complaining that the ISS price is too high.

IIEC's proposal would also stunt the ability of alternative suppliers to develop and offer a similar service. (IP Ex. 11.2, p. 6) If ISS is priced below the price an alternative supplier could offer, "the Commission would virtually guarantee that such alternative services would not be developed." (Id.) Indeed, under IIEC's proposal, RESs would be

[63] Indeed, under IIEC's proposal, these customers will pay less than they would if they were on DA-RTP itself, for all of their load.

given the perverse incentive to use ISS for their customers and to not develop competitive alternatives to ISS. This is bad policy.

IIEC fares no better on its complaint relating to transmission pricing for ISS customers. Essentially, IIEC would prefer that transmission service for ISS customers be billed at network transmission rates rather than point-to-point rates. (IIEC Ex. 1, p. 27) As mentioned above, the transmission pricing in Rider ISS is no different from the current pricing for the same service in current SC 110, and there is absolutely no evidence that any of the 24 customers who have taken ISS have complained about the transmission pricing for that service. Even IIEC admits that this issue is one of "less concern" to it. (Id.) More fundamentally, IIEC fails to recognize that point-to-point pricing is better suited to the nature of ISS service for several reasons.

- *First*, point-to-point billing determinants are a better model for a short-term, uncertain service such as ISS. (IP Ex. 11.1, p. 15)

- *Second*, point-to-point service is available on a daily basis (and can be charged readily on that basis). (Id.) Network service, in contrast, is normally an annual service paid on a monthly basis. (Id.)

- *Third*, because network service was not intended to be used in short-term situations, network service billing determinants can lead to distortions in billings to otherwise identical customers, based solely on which days of which months the customers take ISS. (Id., pp. 15-16) These distortions do not arise under point-to-point service. (Id., p. 16)

Although IP pointed these problems out in the rebuttal testimony of Mr. Peters, IIEC's witness Stephens provided no counter to any of them. Therefore, the Commission should either (1) decide that the IIEC has dropped this issue or (2) decide that based on the evidence in the record, the IIEC's position should be rejected.

In sum, IIEC's proposed changes to the pricing of ISS service should be rejected as contrary to the record evidence and to the Commission's goals relating to this service.

### 3. To Prevent Gaming, Customers Moving From a RES to ISS Should Not Be Able To Return to that RES for One Year

As noted above, one of the fundamental points recognized by this Commission is that RESs should not be allowed to use ISS service as a gaming opportunity. (1999 DST Order, p. 124) One of the provisions in IP's ISS tariff directly prevents RESs from using ISS as a gaming opportunity. Specifically, a customer who is served by a RES and then ends up on ISS cannot return to service from that RES for 12 months. This prevents a given RES from using ISS as a supply option for certain periods but then continuing to serve the customer when prices change favorably. Stated simply, it discourages RESs from dumping customers onto Rider ISS when market prices are high. Of course, it does not prevent the customer from choosing a different RES. Nor is this provision new. (Compare Current SC 110, p. 43 (an ISS customer must either choose a *new* RES or return to bundled service) with IP Ex. 5.9, p. 3 (customer may not be served by its prior RES for a period of one year))

Nonetheless, both Staff and MidAmerican Energy Company ("MEC") opposed this limitation. Staff agrees that RESs should not use ISS for rate arbitrage purposes. (Staff Ex. 7.0, p. 13) Of course, this is only possible if a customer can switch between ISS and the same RES successively. Despite this, Staff is concerned that a customer could be faced with no other supplier (except for the Company). (Id., p. 14) Staff's argument ignores the fact that there are currently 8 RESs in IP's territory. Thus, at a minimum, at least 7 other companies could serve these customers.[64]

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[64] Staff's conjecture regarding residential customers is simply that—conjecture—because no RESs have been certified to serve residential customers anywhere in the State as yet. Indeed, the rules for becoming so certified are not even final at this point. (See Docket 01-0376 (First Notice Rules were issued in November of this year))

Ignoring these facts, Staff proposes removing the limitation on returning from ISS to the same RES and replacing it with hortatory language in SC 150 "that states that suppliers should not use ISS as a supply resource." (Staff Ex. 7.0, p. 14) Notably absent from this language is any penalty imposed on a RES for violating Staff's proposed language. On cross-examination, Staff admitted that none existed: "making this statement in the tariff may not be sufficient to deter a supplier who wishes to place his customer on ISS. And actually giving them some kind of stick might be appropriate, but I haven't proposed one." (Tr. 566) Nor did Staff propose a penalty for a customer who uses ISS as a supply source. (Tr. 566-67) In light of this and the facts of how ISS has been used to date (see Section IV.E.2, above), Staff's proposal is akin to telling drivers not to speed but never ticketing them (indeed, telling them you do not even have the power to ticket them) if they do. This is an unworkable solution.

MEC bases its argument on a faulty factual assertion and an unduly constrained look at one particular scenario where a customer takes ISS. *First*, MEC claims that it is unlikely that a RES could game the system because the RES will see the same market prices used in ISS pricing and therefore DA-RTP plus 10% will always be higher than a RES' price to the customer. (MidAmerican Ex. 1, pp. 3-4) As IP pointed out (and MEC offered no rejoinder in rebuttal): MEC "appears to confuse Rider ISS (which is based on day ahead real time prices) and Rider MVI (with prices which are recalculated every other month). Further, there is no evidence presented by Mr. Phillips [MidAmerican's witness] that RESs have purchased or will actually purchase power and energy at the same market prices utilized in Rider ISS." (IP Ex. 11.1, p. 8) RESs may enter into long-term supply arrangements, while ISS pricing is based on the day-ahead market. Under these circumstances, gaming opportunities can arise whenever the RES can use ISS to supply a customer with energy and then re-sell its existing supply on the open market. (Id.)

*Second*, MEC's focus on a scenario (in which a customer winds up on ISS because it was unable to complete renegotiations of an existing contract and, therefore, wishes to return to the same RES (MidAmerican Ex. 1, p. 4)) is equally misplaced. As IP pointed out (again without any rebuttal from MEC): MEC incorrectly assumes that there are no other options to service on Rider ISS while negotiations with its RES are completed. (IP Ex. 11.1, p. 9) Most obviously, the customer and its current RES could simply agree to interim terms (such using the pricing in the contract that is being re-negotiated or some agreed to interim pricing). Or, the customer could take interim service from another RES. (Id.) In either event, the customer does not lose its ability to retain its current RES once it completes its long-term contract negotiations. Remarkably, however, MEC's own example illustrates the abuse that IP's limitation seeks to curtail: "there is absolutely no reason why IP should be expected to supply a customer while the customer and RES continue negotiations."[65] (IP Ex. 11.1, p. 9)

In light of the problems with Staff's proposal and the record evidence that gaming can occur without a limitation such as contained in IP's Rider ISS, IP's tariff language (limiting return to the prior RES for 12 months) should be adopted and Staff's and MEC's positions rejected.

[65] MEC proposed no alternative to IP's limitation to address the underlying problem.

### F. IP's Provisions Pertaining to Return to Bundled Service from SC 110 Should Be Adopted

#### 1. Customers Should Not Be Able to Rescind Notice of Return to Bundled Service Within the 30-day Notice Period

Under IP's proposed tariffs, once a customer gives IP notice that it desires to return to bundled service, that customer may not rescind that notice during the 30-day period preceding the switch. (IP Ex. 5.1, p. 8) A customer remains free to rescind its notice prior to the final 30-day period, but once it reaches that period, rescission is not permitted. The reason is simple: IP must make supply resource decisions and may end up having purchased power and energy to serve the returning customer. (Id.)

Staff was the only party to disagree with IP's proposal. However, by the time of hearings, Staff agreed that (1) IP should be entitled to recover its legitimate costs associated with a right of rescission, and (2) resolution of this issue would be better handled in a workshop process. (Tr. 563) Given Staff's modified position, IP is willing to work with Staff to see if a resolution of this matter can be reached outside of the current case. In the interim, IP's proposed language should be adopted, especially since no mechanism currently exists for IP to recover its legitimate costs if different language were used.

#### 2. The PUA Permits IP to Require Residential and Small Commercial Customers to Remain on Bundled Service for 24 Months After Returning from Delivery Service

Currently, IP requires that any small commercial customer (as defined in PUA §16-102) who returns to bundled service after having been on delivery service must remain on bundled service for 24 months before returning to delivery services. This provision is in accord with §16-103(d). For residential customers, IP also proposes making the return to bundled rates be 24 months as permitted by §16-103(d). (IP Ex. 5.1, p. 7)

Staff agrees that the law entitles IP to set the return period for residential and small commercial customers at 24 months. (Tr. 568) Staff nonetheless recommends that IP choose a shorter return period. (Staff Ex. 7.0, p. 12) IP is not willing to use a shorter period at this time. The General Assembly expressly authorized electric utilities to include a 24-month return requirement for these customers; thus, Staff's pejorative reference to a "harsh penalty" (id., p. 11) is out of place and misdirected. In any event, the 24-month requirement was part of a broader *quid pro quo* that included obligations on the part of the utility, such as the obligation to continue offering bundled services and the obligation to allow customers to return from delivery services to bundled services on little or no notice. (IP Ex. 5.11, p. 3) Staff's observation that other utilities may have chosen a different approach is irrelevant in light of the clear statutory authorization in §16-103(d). Accordingly, IP's provision requiring a residential or small commercial customer who returns to bundled service from delivery services to remain on bundled service for 24 months must be approved.

### G. IIEC's Arguments Relating to the Departure from, and Return to, Bundled Service Should Be Rejected

IIEC has raised three issues relating to the operation of IP's *bundled* tariffs. (See IIEC Ex. 1, pp. 12-15) Before turning the specific reasons why each of IIEC's positions should be rejected, it is important for the Commission to realize two facts. *First*, not a single bundled tariff that IIEC would like to see modified was filed by IP for modification in this proceeding, as even IIEC acknowledged (Tr. 639). Thus, IIEC seeks to expand the scope of this case beyond what it rightfully should be: a delivery services tariff case. That alone should suffice to reject each of IIEC's contentions. The proper forum for its complaints is a separate proceeding before the Commission, which the IIEC remains free to institute, not the current proceeding. *Second*, the issues IIEC raises are not new; they have been raised by IIEC before and have been rejected by the Commission. (IP Ex. 5.11, p. 14) IIEC raises no new reasons to have the Commission alter its prior decisions. In any event, even if IIEC could get over these two hurdles, its requests do not survive scrutiny.

#### 1. IP's Current Provision in SC 24 on the Notice Required to Terminate an SC 24 Contract Should

Under IP's bundled SC 24, a customer who wishes to terminate service under that tariff must provide 12-month notice to do so (assuming it has already fulfilled its primary term obligation under SC 24). Well before the advent of the current case, IP adopted a policy that permitted a customer to rescind this notice (and thereby remain on SC 24 for another 12-month period) up to 60 days before the termination date. (IP Ex. 5.11, p. 15) Astonishingly, IIEC's own witness did not appear to realize that this policy shift was made "following discussions with the IIEC in early 2000." (Id.) We nonetheless believed this issue to be settled. (IP Ex. 5.12, p. 11) In any event, the IIEC fails to recognize that changing SC 24 has a disparate impact on various large customers. To understand this fully requires some background explanation.

SC 21 and SC 24 are two current bundled tariffs that are designed for customers with loads over 1 MW. These tariffs were in place long before the Customer Choice Law was enacted, with their basic frameworks in place prior to then as well (as even IIEC admits (Tr. 681-82)). SC 21 is the default tariff (i.e., the tariff on which a customer over 1 MW is served assuming it does not choose another available option). Generally, the choice between SC 21 and SC 24 involves a risk/return tradeoff that is embedded in the terms of which the IIEC now complains. (IP Ex. 5.12, p. 12) For example, in exchange for lower power and energy prices, the SC 24 customer commits to a longer primary term (5 years), longer notice to terminate service outside the primary term (12 months) and a guaranteed energy commitment than would occur for an SC 21 customer.[66] Thus, it is the customer's choice under which rate it would like to be served, but, when it makes that choice, it knows (after weighing carefully) the obligations (and opportunities) that come with each rate. (See generally IP Ex. 5.12, p. 12)

Simply stated, IIEC is attempting to eliminate one of the *obligations* of SC 24 while retaining its advantageous characteristics for customers compared to SC 21. This maneuver should not be allowed, particularly in the context of a *delivery services* case. IIEC's proposal must be rejected.

### 2. A Customer Should Not Be Able to Return to SC 24 Without Complying with the Primary Term Requirements of the Filed Tariff

Along the same lines as its attempt to permit SC 24 customers (who have satisfied their primary term obligations) to move off the tariff more quickly than its terms allow, IIEC also wants to permit these customers to be exempt from the primary term requirement of SC 24 if they *return* to SC 24 after taking delivery services. (IIEC Ex. 1, pp. 13-14; IIEC Ex. 4, pp. 9-10) Again, IIEC refuses to focus on the interplay between SC 21 and SC 24, even though it admitted that the two rates must be looked at in conjunction and not in isolation. (Tr. 683) IIEC's proposal is discriminatory to SC 21

[66] Generally, the primary term under SC 21 is one year but, IP changed the term for SC 21 customers in 1999 to 30 days, assuming the customer was willing to reimburse IP for any unrecovered cost of facilities. A thirty-day notice to cancel is also accepted outside the primary term, and there is no guaranteed energy level required under SC 21.

customers. (IP Ex. 5.12, p. 12) The source of the discrimination can be seen by looking at two customers who both began service in 1995 and who are otherwise identical except that one chose to take SC 21 and the other SC 24. (Id.) If both customers take delivery services for a year and then return to bundled service, under IIEC's proposal, the former SC 24 customer can still obtain the lower pricing of SC 24 and be free to return to delivery services a year later while the SC 21 customer (who paid more for the five years it was served under SC 21) will be require to be on SC 24 for 5 years if it wishes to obtain the lower prices that tariff offers. Fundamental fairness requires that the IIEC's position be rejected.

### 3. Customers Who Choose Delivery Services Should Not Be Able to Return to Bundled Tariffs That Are Closed

IIEC's final out-of-place gambit with IP's bundled rates is to reopen IP's closed interruptible tariffs, at least for those customers who are on them currently and subsequently choose to leave them to go on delivery services and would then like to return to the closed rate. (IIEC Ex. 1, p. 14; IIEC Ex. 4, p. 11) Again, the IIEC seeks a discriminatory change in IP's bundled tariffs to benefit a few customers.

IP has consistently administered its policy that its closed interruptible tariffs (i.e., SC 30 and Rider S) are closed and will not be "re-opened" to customers who choose to leave those tariffs (for whatever reason). (IP Ex. 5.12, p. 13) Thus, for example, customers who left these rates (in order to firm up their service) prior to the Customer Choice Law becoming law, cannot return to these rates. (IP Ex. 5.11, p. 17) Similarly, those customers who made the same decision after the law was passed are also ineligible to return to them. (Id.) And, those that have already taken delivery services are ineligible to take service on the closed interruptible rates. (Id.) Thus, what IIEC seeks is a discriminatory waiver to IP's longstanding, consistent practice to benefit those few customers who remain on these closed rates and have not yet taken delivery service. As with IIEC's other proposals, this is not fair to those customers who made choices based on a certain set of rules that IIEC now does not wish to follow. It is also unfair to IP to require it to provide a safety net of interruptible service on rates that have been closed for a decade.[67] (IP Ex. 5.11, p. 17) This is particularly true since these rates are frozen until 2005 under PUA §16-111(a) -- IP cannot raise them to reflect the current cost of service. Under these circumstances, IIEC's proposal to reopen closed bundled tariffs that are not even at issue in this case should be rejected.

### H. A Retail Delivery Services Customer Remains Responsible for OATT Charges Not Paid by the Customer's TSA or RES

IP's proposed DSTs include language that makes it clear that a retail customer remains ultimately liable for transmission charges if its RES or Transmission Service Agent ("TSA") fails to pay those charges. (See IP Ex. 5.5, p. 29) However, IP's tariff language also makes it clear that "Before billing the charges to Customer, Utility shall first pursue all reasonable collection actions against Customer's RES . . . or TSA, including initiating a claim against any bond or other security the RES . . . or TSA has posted." (Id.)

[67] In implicit recognition of the flawed nature of its proposal, IIEC proposes to "limit" its effect only until IP's interruptible rates are declared competitive by the Commission. (IIEC Ex. 1, pp. 14-15) This limitation is worth little since once these services are declared competitive, IP will likely cancel them in any event. (IP Ex. 5.12, p. 13) Furthermore, if IP must provide IIEC's "open season" (IIEC Ex. 1, p. 15), alternative suppliers will find it that much harder to develop competitive alternatives to these services since customers will know they have a risk-free option to return to the closed service at frozen rates that were set 10 years ago.

Under IP's OATT, the retail delivery services customer is the transmission customer; the TSA or RES is acting as the retail customer's agent (assuming the retail customer does not take service directly under the OATT). (IP Ex. 5.11, p. 5) Thus, IP's proposed language merely puts the retail customer on notice of an indisputable foundation of agency law: the principal remains liable for debts incurred by its agent on its behalf.

Staff opposes IP's language for several reasons. First, it disputes whether in fact the OATT establishes the retail customer as the transmission customer and creates an agency relationship when a different party actually works on behalf of that customer. (Staff Ex. 8.0, p. 4; Staff Ex. 17.0, p. 3) However, the Staff witness disputing IP's claim (1) is not a lawyer, (2) has not gained any special understanding of agency law based on work experience and (3) has not had responsibility for day-to-day implementation of a utility's OATT. (Tr. 470-71) Thus, there is little more than conjecture by Staff's witness to dispute the status of the customer as the transmission customer. In contrast, IP described the applicable sections of IP's OATT and explained how those provisions supported IP's position. (IP Ex. 5.11, p. 5)

IIEC takes a slightly different tack and attempts to change IP's OATT via changes in IP's DSTs. (IIEC Ex. 4, pp. 27-29) This, of course, the Commission cannot do: "An electric utility shall provide the components of delivery services that are subject to the jurisdiction of the Federal Energy Regulatory Commission at the same prices, terms and conditions set forth in its applicable tariff as approved or allowed into effect by that Commission."[68] (Section 16-108(a)) IIEC's attempts must be rejected.

Staff goes on to focus on items that are essentially irrelevant to this issue or that actually bolster the appropriateness of IP's DST language. *First*, Staff focuses on whether or not TSAs or RESs are bad credit risks. (See generally Staff Ex. 8.0) As the Staff witness admitted later, however, he was not claiming the Commission's current credit requirements in the Commission's ARES certification rules are inadequate to prevent non-creditworthy RESs from being certified. (Staff Ex. 17.0, p. 12)

*Second*, Staff focuses on whether additional language should be added to existing Letters of Agency ("LOA"). (See generally Staff Ex. 8.0; Staff Ex. 17.0) IP is willing to add additional language to its LOA if the Commission believes this would be appropriate. (IP Ex. 5.11, p. 7) What is remarkable about this line of Staff's testimony is its incongruity with Staff's basic tenet that the same notice should *not* be included in SC 110. (Compare Staff Ex. 17.0, p. 3 ("if the OATT establishes the agency relationship alleged by the Company, then the language set forth in SC 110 is not needed and should be deleted.")) But, as Staff admits, if an agency relationship is created by the OATT, that relationship remains in place regardless of whether IP's SC 110 notifies the retail customer of this fact or not. (Staff Ex. 17.0, p. 3; Tr. 475-76) Thus, more notice, not less, should be appropriate, which is IP's proposal.

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[68] During cross-examination, Staff agreed that every element of the quoted sentence of §16-108(a) was present in the current situation: delivery services are offered to retail customers, delivery services include transmission service, transmission service is provided under the OATT over which the Federal Energy Regulatory Commission has jurisdiction. (Tr. 474-75)

In any event, IP is willing to work with Staff to create more effective notice to retail customers, whether that notice is set forth in SC 110, IP's DSIP, an LOA or some other document. (Compare Staff Ex. 17.0, p. 8 (acknowledging that language proposed by IP on rebuttal was an "improvement")) IP does not, however, agree to proposed resolutions that misconstrue the OATT or are at odds with agency law, and which the Commission is not authorized to implement. For these reasons, IP's proposed language is appropriate and should be approved.

### I. The Parties Have Reached a Reasonable Conclusion Regarding An Agreement for "Billing Agents" Relating to Collection and Remittance of IFC Charges

Although at one point this was an issue in this case, the parties reached an agreement on the text of the agreement that should be used to cover situations where a third party collector bills electric retail customers for IP's services that include IFC charges. (Tr. 621-22; MidAmerican Cross Ex. 1. *Cf.* Tr. 564) In light of the parties' resolution of this issue and the lack of any objection to it in the current record, the Commission should approve IP's revised language to Section 6(u) of its Standard Terms & Conditions (set forth in IP Ex. 3.17, p. 18) and the use of MidAmerican Cross Exhibit 1 as a generic agreement that fulfills IP's (and a third party collector's) obligations under Section 6(u).

### J. The Parties Agree that the Issue of Permitting Electronic Signatures for Customer-RES Letters of Agency Is Better Resolved in a Separate Forum

Staff raised an issue regarding whether IP should permit electronic signatures (as compared to "wet" signatures) to be valid for customers "signing" an LOA. (Staff Ex. 7.0, pp. 6-10) Staff recognized that its proposal raised issues that might be better resolved in a workshop process and suggested that such a process be initiated for interested parties. (Id., p. 10; see also Tr. 561) While IP has some concerns about the use of electronic signatures (including their legality given the current wording of various applicable statutes), it is not opposed to them in the abstract and is willing to work with Staff in workshops to resolve various issues surrounding their use. (IP Ex. 5.11, pp. 2-3) In light of the consensus among those parties who provided testimony on this issue that this issue is better addressed in workshops, the Commission should not attempt to resolve this issue at this time but rather permit the parties a chance to resolve this matter informally.

### K. The Commission Should Not Require IP to Split Electric and Gas Bills and Accounts At This Time

MEC proposed that IP split the bills and accounts of combination gas and electric customers. (See MidAmerican Ex. 1, p. 3; MidAmerican Ex. 2, pp. 5-6) Staff (though generally in favor of splitting accounts) recognizes that doing this may impose both administrative burdens and added cost on IP and thus proposes a lesser step: that IP identify the costs associated with splitting bills and accounts. (Staff Ex. 16.0, pp. 10-11)

The most remarkable aspect of MEC's testimony on this issue is what is does *not* say: at *no* point does MEC recognize the cost imposed by its request, *nor* does it agree that customers or RESs who impose this cost should pay for it. While that may have been an inadvertent omission in MEC's direct testimony, the continuing silence in MEC's rebuttal testimony is tantamount to an admission that it is looking for a free ride. As MEC is surely aware, splitting bills would benefits agents such as MEC. (IP Ex. 5.11, p. 20) Therefore, MEC should be willing to pay for the benefit. Moreover, IP has received few inquiries to date to split bills. This indicates that, in general, there is insufficient interest for IP to incur the costs needed to implement this proposal—and even less reason to socialize those costs among the vast majority of parties that do *not* want split bills. (See id.) MEC presented no evidence that, in fact, there is a groundswell of interest in splitting bills (presumably because none exists).

In any event, Staff is correct that splitting bills raises a host of administrative issues for IP, such as disconnect procedures, call center efficiency and customer histories. (IP Ex. 5.12, p. 7) Furthermore, because this issue first arose in MEC's direct testimony (in which MEC made no offer regarding payment of the cost), IP was not able in the time available in the latter stages of this case to identify all of the costs associated with splitting bills. (Id.) Nonetheless, programming costs alone necessary for IP to be able to split bills and accounts could be in excess of $250,000. (Id.)

Furthermore, splitting bills is not just an issue for IP, but poses costs and administrative issues for all combination utilities. Indeed, if this requirement is ever imposed on IP, it should be imposed on all combination utilities. (Id., p. 15)

Rather than rush headlong into a costly action for which there seems to be little interest, and which raises myriad administrative concerns, IP proposed that these issues be addressed in a workshop process or a generic docket in which all parties (including other combination utilities) could voice their concerns and time would permit the parties to better analyze the issues. (IP Ex. 5.12, pp. 15-16) IP's proposal strikes a proper balance and will lead to a more informed decision on this issue than can be arrived at based on the record in this proceeding. In no event should MEC's ill-conceived and unsupported request be adopted, given the record in this case.

## V. CONCLUSION

For the reasons set forth in this Brief, the Commission should approve the electric distribution revenue requirement (Section II above), revenue allocation and rate design for the delivery services tariffs (Section III above), and other terms and conditions of delivery services (Section IV above) proposed by Illinois Power Company in this case.

Respectfully submitted,

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